Canada–B.C.
Conservation and Renewable Energy Demonstrations

A FEASIBILITY STUDY OF THE CONCEPT OF COGENERATION FOR THE METROPOLITAN VICTORIA AREA BASED ON THE USE OF REFUSE DERIVED FUELS

Energy, Mines and Resources Canada
Conservation and Renewable Energy Branch

Energie, Mines et Ressources Canada
Bureau de la conservation et des énergies renouvelable

Province of British Columbia
Ministry of Energy, Mines and Petroleum Resources
CONSERVATION AND TECHNOLOGY DIVISION

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A REPORT TO

Energy Conservation and Technology Division
Ministry of Energy Mines and Petroleum Resources
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by

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Report ECR-82-1

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The responsibility for the content of this report is the consultants' alone, and the conclusions reached herein do not necessarily reflect the opinions of those who assisted during the course of this investigation of the Federal and Provincial governments which funded the study.

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PREFACE

Following a submission to the Ministry of Energy, Mines & Petroleum Resources, Government of the Province of British Columbia, in October 1979, it was agreed that the Capital Regional District, in conjunction with specialized consultants, undertake a "Feasibility Study of the Concept of Cogeneration in the Victoria Metropolitan Area based on the use of Refuse Derived Fuels". This report outlines the methodology, results and conclusions of that study.

Further, it was agreed that the two principal objectives of the feasibility study would be:

1. To determine the economic and technical viability of cogeneration within the Victoria Metropolitan Area.

2. To establish a procedure upon which local governments, other than the Capital Regional District, could evaluate the economic and technical viability of cogeneration within their own areas.

In order to meet these two objectives the study was divided into two specific areas of expertise. One part consisting of the technical evaluation and the other consisting of the economic evaluation. The Capital Regional District acting as project manager for the study engaged two principal consultants to undertake the work involved in each area of the study.

The principal consultant engaged to perform the technical evaluation was B.H. Levelton & Associates Ltd., Vancouver (BHL). BHL were assisted by two other technical consultants. D.W. Thomson Consultants Ltd., Victoria were responsible for identifying the markets for the potential sale of steam in the Victoria Metropolitan area. They also developed two steam distribution systems to supply steam to specific markets and identified the capital and operating costs of the systems. Intercontinental Engineering Ltd. (INTEG) was responsible for the design of the power plant. In particular, INTEG identified the size and layout of the equipment required and developed capital and operating costs for the power plant.

B.H. Levelton & Associates Ltd. was primarily responsible for analyzing the present and future refuse, and its by-products, produced in the area, the design of the RDF plant together with establishing an estimate of its construction and operating costs and also for establishing the price of steam and electricity sold. BHL apart from reviewing and co-ordinating all the technical aspects of the feasibility study was responsible for the compilation of the main volume of this report.

The principal consultant engaged to perform the economic evaluation was Richard J. Brewer & Associates. Their report entitled "Financial Analysis and Economic Evaluation of the Concept of Cogeneration in the Victoria Metropolitan Area" is presented as an addendum to the report by BHL. The two reports should, however, be read in conjunction with each other.

A free exchange of ideas between the two principal consultants and the Capital Regional District, permitted a number of areas to be examined which could otherwise have been overlooked. The study, although taking longer than anticipated is considered to be fairly exhaustive and the conclusions drawn from the study are considered to be practical and realistic.

PART I - BACKGROUND INFORMATION FOR THE STUDY

I. INTRODUCTION

A. Definition of the Capital Regional District

The CRD consists of thirteen Municipalities, Districts and Areas. For convenience these can be described as:

1. Core Area - The Municipalities of Victoria, Esquimalt, Oak Bay and Saanich, often referred to as Greater Victoria.

2. Peripheral Area - The unorganized Districts surrounding the Core including View Royal, Colwood, Metchosin, Langford, Central and North Saanich. Sidney is also included here for geographical reasons appreciating that its population density approaches that of the urbanized Core Area.

3. Island Area - Saltspring and the Outer Islands of Galiano, Mayne, Saturna, North and South Pender.

4. Western Area - This corresponds to Sooke Electoral Area and comprises all land west of the Langford-Metchosin western boundaries.

Plate 1 shows the CRD component areas.

B. History of Waste Disposal in the CRD

1. Past Practice

Throughout the years, municipal refuse has been disposed of primarily by landfilling at a number of sites. Heap burning of such refuse was common until prohibited by the Public Health Officer, later supported by the Pollution Control Branch.

At the present time all municipal refuse from the Core and Peripheral Areas is disposed of at the Hartland Road Landfill site, which was purchased from Victoria Disposal Co. Ltd. in 1975 Refuse is delivered to the site by municipal trucks, by disposal contractors and by private vehicle. The landfill is operated by Victoria Disposal Co. Ltd. under contract to the CRD.

In the Western Area and the Island Area, refuse is landfilled, there being no provision for removing the refuse to the Hartland Road Site.

It is probable that some refuse is incinerated or buried at private residences in those areas which are lightly populated and which provide adequate land space for such forms of disposal. Such practices reduce the potential amount of refuse available at the central disposal site.

Plate 2 shows disposal sites in the CRD as of April 1974. The quantities given are, of course, no longer applicable, and the Sooke Landfill Site, Scheme B, was never installed. The other sites with the exception of Chew and Millstream still exist.

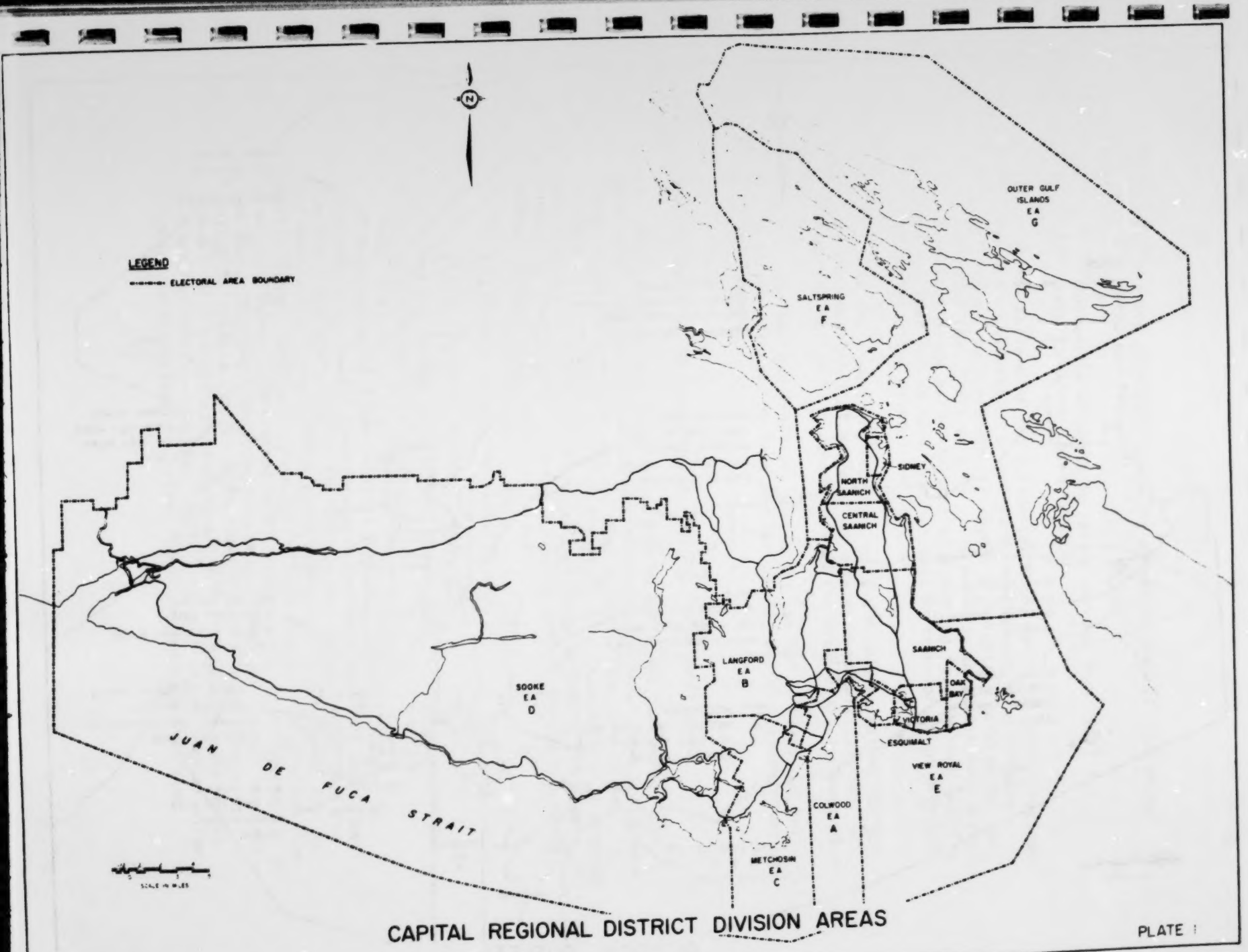
2. Previous Studies

McLaren (1) prepared a report on the long-term prospects for solid waste disposal in the CRD. It suggested that landfill was a preferred method of solid waste disposal.

In 1974, B.H. Levelton & Associates Ltd. and Dayton & Knight Ltd. conducted an in-depth study of the alternatives open to the CRD for waste disposal to the year 2000. This study found that landfilling provided the least cost method for waste disposal and recommended that:

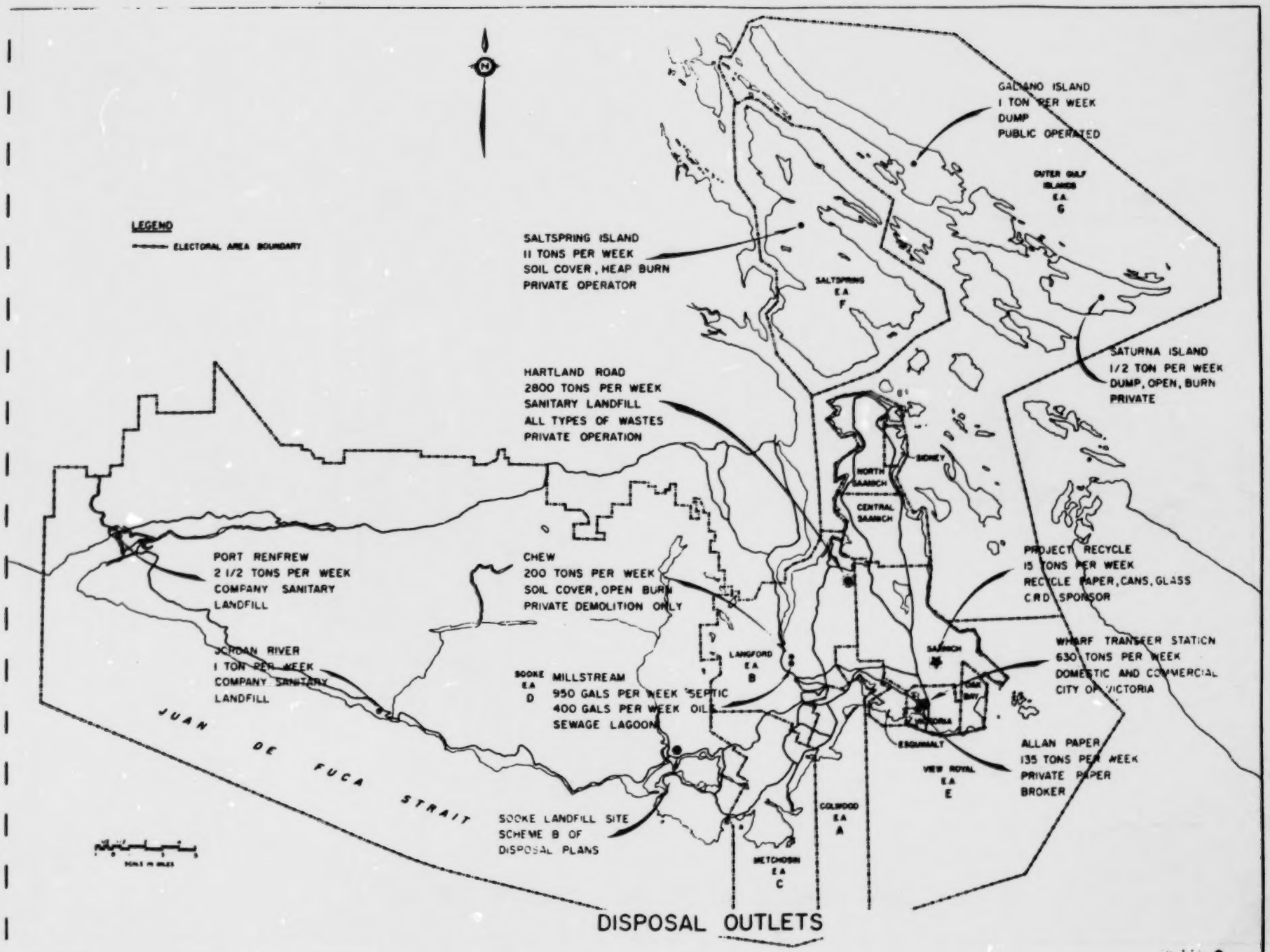
- the CRD must have control of all refuse generated within the Region, and, hence, should purchase or directly oversee existing landfills;
- a new landfill should be constructed, preferably in the Sooke Area;
- wastes from the Islands should be transported to one of the landfills in or near Victoria.

Subsequent discussion by the Regional Board of Directors led to a stated CRD policy of recovering energy and other resources from municipal waste if at all feasible. Since the 1974 report did not examine all aspects of energy recovery in detail, a further study by B.H. Levelton & Associates Ltd. (3) was undertaken in 1976. This report considered the various known technologies for energy and resource recovery as applied to the CRD. At that time the processes which offered some hope of being economic were:



CAPITAL REGIONAL DISTRICT DIVISION AREAS

PLATE I



DISPOSAL OUTLETS

- flash pyrolysis producing a combustible oil (Occidental Petroleum Process);

- conversion of waste to refuse dervied fuel (RDF) for sale to solid-fueled furnaces.

The failure of the occidental Petroleum pilot plant precluded further consideration of any early development of a suitable solids-to-liquid process. A search of potential markets for RDF indicated that there were no users prepared to accept such a fuel even at a price below the cost of producing it. The availability of hog fuel for no more than the cost of transportation made RDF an unattractive alternative fuel.

At one time there appeared to be a promising market for RDF at the Department of National Defence at Esquimalt (4), but negotiations never proceeded beyond the preliminary interest level.

The DND had indicated they might use RDF in their own boiler(s), a scheme prompted by Cade and Barton (5), but the scheme never was initiated.

C. The CRD Decision to Proceed with Planning for Cogeneration

Municipal refuse has continued to be delivered to the Hartland Road Landfill, the only disposal site in the CRD other than small landfills in the Western Area and the Gulf Islands. The life of the Hartland Fill is limited so that CRD staff felt it necessary to proceed with firm plans for alternative means of waste disposal, preferably compatible with the CRD's stated policy of resource recovery. Three general possibilities were considered:

- development of another landfill, etc.;

- simple incineration of refuse;

- burning refuse in a central power plant to produce steam and electricity.

Development of a new landfill site is attractive in that it involves least capital investment and represents a known technology. However, potential sites in the CRD are not favourably located for refuse transport and delivery costs probably will be higher than to Hartland Road, even with installation of a new transfer station (the area near Sooke is considered to offer the best site conditions). In addition, landfills lead to environmental problems through leachate control (already a problem at Hartland Road). Landfilling costs probably will escalate beyond normal inflation because land values continue to increase, so that landfilling, per se, will never allow disposal costs to remain constant let alone decrease with time.

Incineration is a viable means for disposing of municipal refuse, well proven in many communities. It does not provide for energy recovery and unit costs will escalate with time because some supplementary fossil fuel is usually required. Present disposal costs in modular incinerators in areas similar to the CRD range between $10 and $20 per ton of refuse.

The concept of cogeneration is attractive to the CRD in that both resource materials and energy can be recovered. Preliminary calculations have indicated that cogeneration is attractive if a significant amount of steam can be sold as well as all of the electrical energy developed. The CRD recognized that a detailed study of the feasibility of cogeneration was required prior to proceeding with firm plans. Accordingly, in October 1979, the CRD submitted a proposal requesting funding for such a study to the British Columbia Ministry of Energy, Mines and Petroleum Resources. This proposal resulted in funding of the study under the Federal-Provincial grant system. This report presents the findings of that study.

II. AMOUNT AND NATURE OF WASTES IN THE CRD

A. Municipal Refuse in the CRD

1. Definition of Municipal Refuse

Municipal refuse comprises wastes produced in and collected from private homes, institutions, hotels and motels and commercial establishments. In the CRD it will include wastes from the Department of National Defence (DND) and from various government laboratories, always provided such wastes are acceptable at the landfill.

Refuse is delivered to the Hartland Road Landfill in a variety of ways:

- by municipal collection vehicles;
- by private refuse collection contractors;
- by private vehicles;
- by transport truck from the Victoria Transfer Station (all Victoria refuse is delivered to a transfer station on the Inner Harbour, from which it is moved to Hartland Road by a contractor, Victoria Disposal Co. Ltd.

Details of collection procedures are contained in Reference 2.

2. Records of Waste Production

Prior to 1977, quantities of refuse produced in the CRD were estimated. All data in, "Capital Regional District Solid Waste Disposal", Reference 4, were derived from collectors best estimates and limited measurements of truck loads using portable scales. These early figures for waste production probably are not accurate because of variations in collection practice among municipalities. For example, in one municipality, collection vehicles operate until fully loaded, even though the collection period may span two days, while in another, collections proceed through the working day only and trucks are discharged at the landfill daily. Any attempt to estimate refuse weight from numbers of trucks must take into account these varying practices.

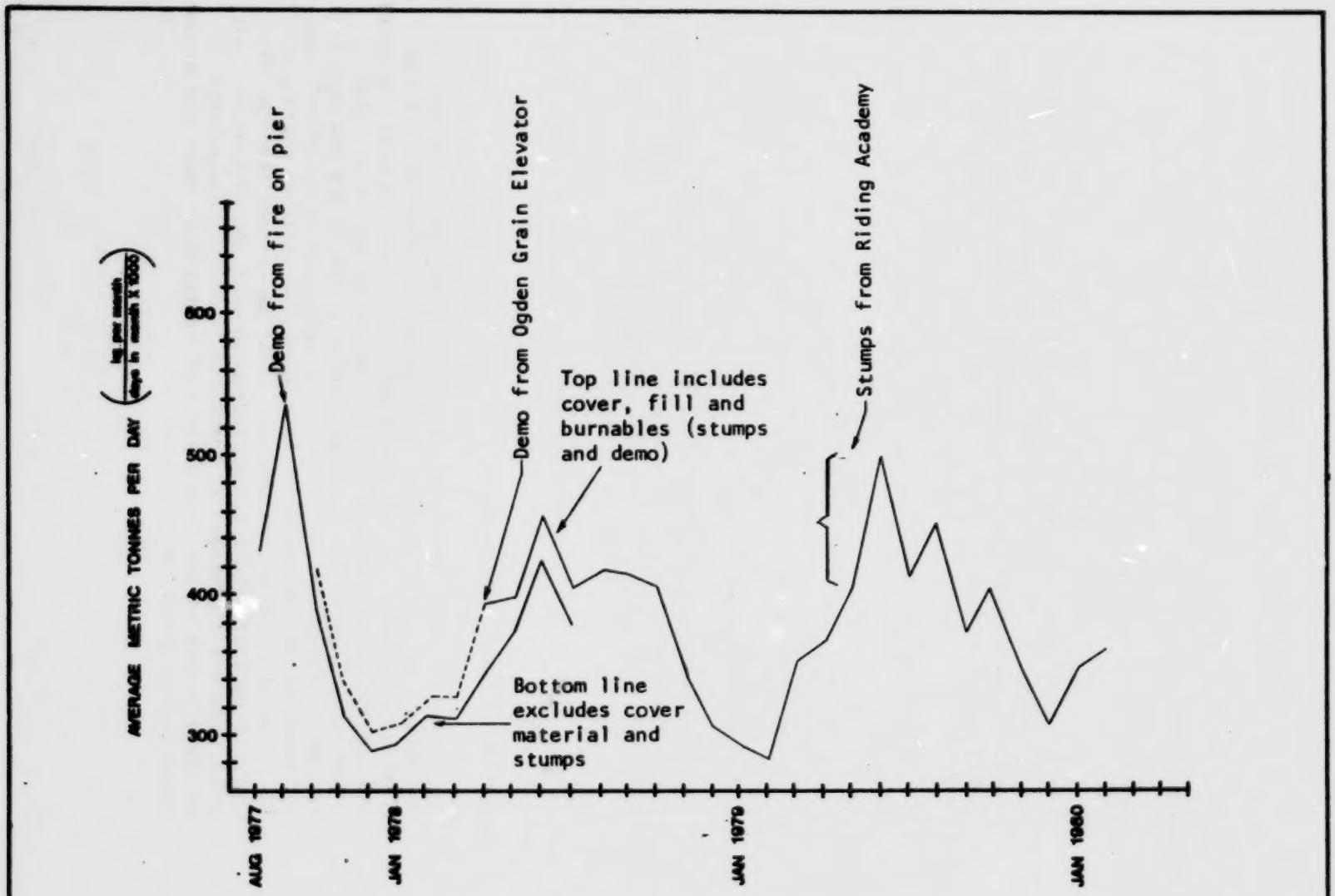

AVERAGE METRIC TONNES PER DAY (kg per month / days in month X 1000)
800
500
400
300
Demo from fire on pier
Demo from Ogden Grain Elevator
Top line includes cover, fill and burnables (stumps and demo)
Stumps from Riding Academy
Bottom line excludes cover material and stumps
AUG 1977
JAN 1978
JAN 1979
JAN 1980

Figure 1. Daily Tonnage of Solid Wastes Delivered to Hartland Landfill.

In August 1977, a permanent scale was installed at the Hartland Road Landfill and true weights of refuse delivered to the site are recorded. Table I lists weights delivered in each month. Note that the first column lists weights excluding demolition and construction residues and column two shows weights of such residues. Figure 1 shows average daily waste quantities delivered to the landfill. These weights (in metric tons) are calculated by dividing the monthly delivered quantity by the total number of days in that month. It is standard procedure to express waste generation in tons per day (or tonnes per day) even though pick-up and delivery to the landfill occurs only for five days of the week.

Figure 1 shows clearly seasonal variations in refuse generation as well as the contribution of demolition refuse to total waste delivered to the landfill. Seasonal variations in the CRD (as in other cities) result from:

- inclusion of grass cuttings, etc. in garbage;

- heavy tourist influx during the summer.

Demolition refuse has not been considered as a fuel for a cogeneration plant, primarily because it is very difficult to handle (long board lengths, concrete chunks, etc.). Earlier studies in the CRD (2) have indicated that demolition refuse might at times represent up to 30% of total refuse delivered to the landfill. The effect of such incidents as the pier fire on total waste delivered are evident in Figure 1.

Table II shows a summary of solid waste estimated for the CRD in 1973. The data are almost certainly incorrect for 1973 (probably too high) but are of value in showing the distribution of waste generation. Individual contributions will have changed as municipalities grow. For example, Victoria, being near saturation population, will not have grown as rapidly as Saanich and some of the peripheral areas. It is interesting that the total listed for the CRD in 1973, 3016 tons per week or 431 tons per day, is only slightly below the average measured generation rate in 1977-1979 (Figure 1).

Table III shows daily per-capita generation rates for the CRD. These data are presented to show variations within the Region and to illustrate the differences between countries and areas of countries.

TABLE 1

WEIGHT OF REFUSE DELIVERED TO

THE HARTLAND LANDFILL

MONTH & YEAR	WEIGHT EXCLUDING CONCRETE, STUMPS AND FILL (kg)	WEIGHT OF CONCRETE, STUMPS, AND FILL (kg)
August, 1977	14,073,265	
September	16,726,910	
October	12,734,180	
November	10,120,780	
December	9,623,880	
January, 1978	9,824,630	
February	9,289,690	
March	10,274,910	
April	10,982,070	
May	12,232,100	735,670
June	13,389,710	983,480
July	12,453,680	662,790
August	13,190,577	396,950
September	12,572,900	448,400
October	12,105,110	1,065,670
November	10,822,900	437,860
December	9,900,620	187,840
January 1979	9,480,810	209,980
February	8,[illegible]3,760	145,730
March	10,911,640	666,010
April	11,148,140	358,280
May	12,112,020	1,063,070
June	13,786,160	1,836,200
July	12,709,610	725,030
August	13,666,180	520,470
September	11,395,700	499,230
October	11,098,760	2,073,110
November	9,791,820	1,318,680
December	8,962,630	1,138,760
January 1980	8,856,770	2,573,820
February	8,826,040	2,216,700

TABLE 11

CRD - CHARACTERISTICS AND SOLID WASTE GENERATION - 1973

PATTERN AREA	MUNICIPALITY OR DISTRICT	AREA (sq mi)	POPULATION X 1000	POPULATION DENSITY (persons per sq mi)		WEEKLY WASTE GENERATION						GENERAL METHOD OF WASTE DISPOSAL
						TOTALS				PER-CAPITA		
						VOLUME		WEIGHT		WEIGHT	VOLUME	
				TOTAL	URBANIZED ONLY	AMT (cu yd)	% of Total	AMT (ton)	% of Total	(lb)	(cu ft)	
CORE	Victoria	8.1	68.4	8,450	8,450	7,900	62.0	1,520	50.0	44.5	3.1	Municipal pickup to Transfer Station to Landfill.
	Saanich	40.0	67.0	1,670	2,800	2,300	18.0	700	23.0	21.0	0.9	Municipal pickup to Landfill.
	Oak Bay	4.5	18.5	4,100	4,100	650	5.0	210	7.0	22.5	0.9	Municipal pickup to Landfill.
	Esquimalt	3.0	13.0	4,300	4,300	750	6.0	320	10.5	49.0	1.6	Municipal pickup to Landfill.
FOR CORE ONLY		55.6	166.9	3,000	4,100	11,600	91.0	2,750	91.0	33.0	1.9	
PERIPHERAL	Central Saanich	16.6	5.1	310	2,300	60	0.5	16	0.5	6.5	0.3	Private Collect or to Landfill.
	N Saanich	16.4	4.0	240	870	50	0.5	13	0.5	6.5	0.3	Private Collect or to Landfill.
	Sidney	2.4	5.2	2,200	2,700	400	3.0	90	3.0	35.0	2.1	Private Collect or to Landfill.
	Colwood	8.9	8.1	910)								
	View Royal	4.8	4.1	850)		450	3.5	115	4.0	9.0	0.5	Private Collect or to Landfill.
	Metchosin	28.3	1.7	60)								
	Langford	70.7	9.8	140)								
FOR PERIPHERAL ONLY		148.1	38.0	260		960	7.5	234	8.0	13.0	0.7	
WESTERN	Sooke	662.0	4.9	7		75	0.5	17	0.5	7.0	1.0	Private Collect to central landfill plus local landfill for isolated communities
ISLAND	Saltspring	76.0	3.2	40		80		12				Private Collect to central landfill plus local landfill for isolated communities
	Outer Islands	59.0	1.4	25		30		3				
FOR ISLAND ONLY		135.0	4.6	35		110	1.0	15	0.5	6.5	0.6	
CRD		1000.0	214.4	220		12,800		3,016	100.0	27.5	1.6	

TABLE III

PER-CAPITA GENERATION OF MUNICIPAL REFUSE

IN THE CRD (1973 CALCULATION)*

AREA	DAILY PER-CAPITA GENERATION (lb) WITHOUT DEMOLITION
Victoria	3.5
Saanich	2.0
Oak Bay	2.0
Esquimalt	4.2
Peripheral Area	2.0
Western Area	1.0
Island Area	1.0
Canadian National Average	4.5
GVRD	3.3
USA National Average	5.3
CRD Average	2.4

*Data from Reference 2.

3. Predictions of Growth of Waste Quantity

Projections of refuse generation are usually made on the basis of population growth, it being assumed that per-capita generation remains roughly constant. Table IV shows population growths in the CRD through 1976.

The CRD Planning Department suggests that the population increase through 1996 will be between two and three percent per year. Obviously the larger areas will have more immediate influence on absolute population growth than the smaller areas but the peripheral areas will experience the greatest percentage growth.

For this study it has been assumed that population and waste generation will grow at 2.3% per year above linear. Assuming the present average waste generation rate is 419 tpd the data of Table V and Figure 2 are obtained.

The projected waste generation values are not certain. It is probably conservative to state that waste generation will be directly proportional to population but any changes in packaging and in consumer habits can alter per-capita waste generation. In recent years there has been a trend in the CRD for waste volumes to remain relatively constant and the volume flow through the Victoria Transfer Station actually decreased one year. Elsewhere in North America, waste generation rates have increased with urbanization, so that assumption of constant per-capita generation may lead to a lower than correct quantity of refuse. Actually, the rather small changes which occur from altering assumptions will not have major effects on the feasibility of co-generation.

4. Composition of Waste

The composition of CRD refuse was determined by B.H. Levelton & Associates Ltd. (2) in 1973 and 1974. Three sets of measurements are given in Tables VI, VII and VIII. The data in Tables VI and VII probably reflect truer compositions of CRD municipal refuse than the data of Table VIII which includes major amounts of demolition refuse. At that time demolition refuse was a major contributor to waste taken to the Hartland Road Landfill.

TABLE IV

POPULATION GROWTH IN THE CRD, 1971 TO 1976

(Based on CRD Planning Department Data)

AREA	POPULATION		YEARLY GROWTH %
	1971	1976	1971 - 1976
Victoria	61,760	62,551	0.25
Saanich	65,040	73,383	2.44
Oak Bay	18,430	17,658	-0.85
Esquimalt	12,925	15,053	3.10
Colwood	8,101	9,838	3.96
Langford	9,587	13,129	6.49
View Royal	3,671	3,609	-0.34
Metchosin	1,590	2,861	12.47
Central Saanich	5,135	7,413	7.62
North Saanich	3,600	4,697	5.46
Sidney	4,865	6,732	6.71
Indian Communities	1,095	1,326	3.90

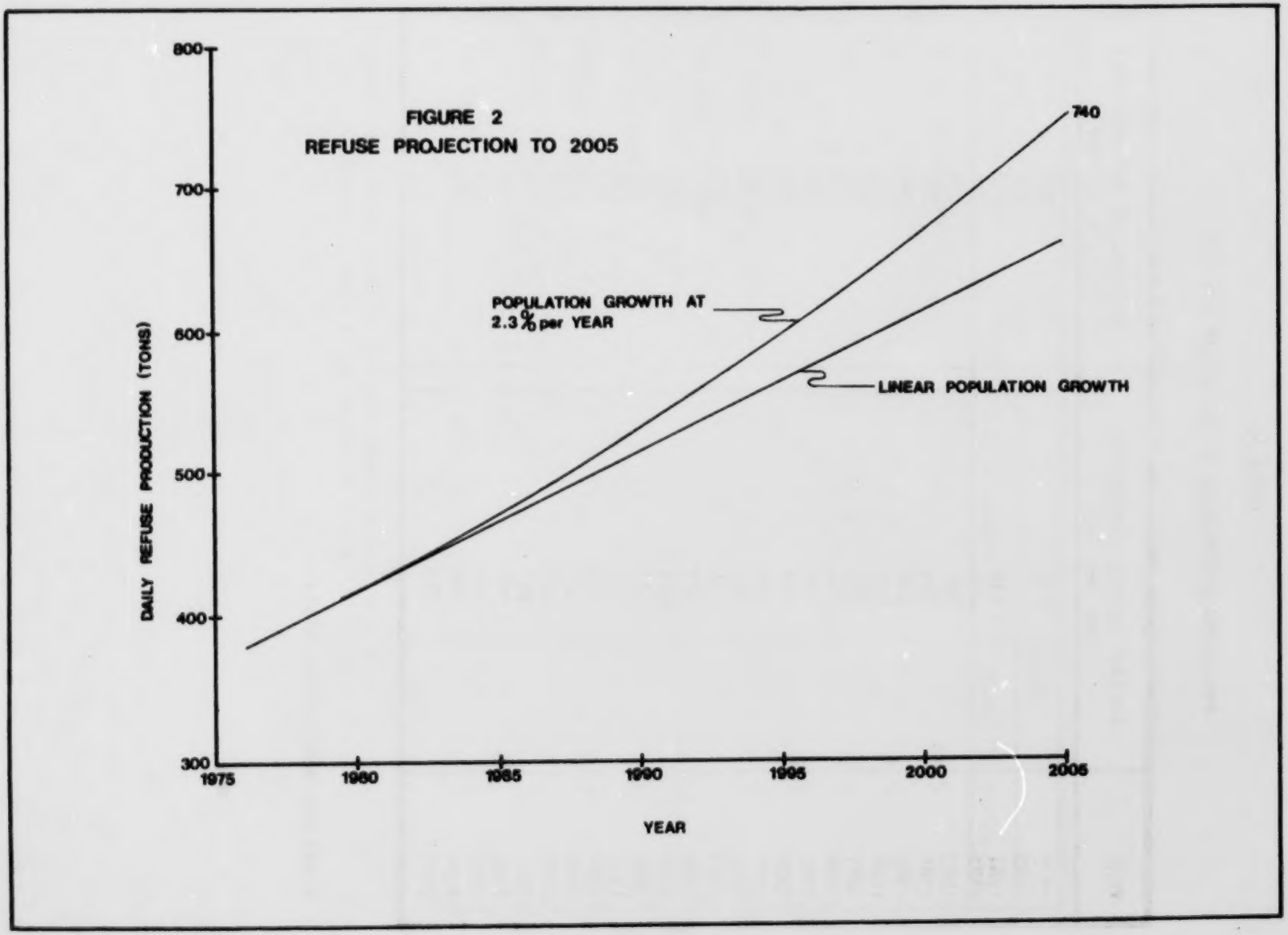


FIGURE 2
REFUSE PROJECTION TO 2005
800
700
600
500
400
300
DAILY REFUSE PRODUCTION (TONS)
740
POPULATION GROWTH AT
2.3% per YEAR
LINEAR POPULATION GROWTH
1975
1980
1985
1990
1995
2000
2005
YEAR

TABLE V

PROJECTED GENERATION OF REFUSE IN THE CRD

YEAR	AVERAGE REFUSE GENERATION (tons per day)	EQUIVALENT RDF AVAILABLE (tons per day)
1979	419	209
1980	429	214
1981	438	219
1982	449	224
1983	459	229
1984	469	234
1985	480	240
1986	491	245
1987	503	251
1988	514	257
1989	526	263
1990	538	269
1991	550	275
1992	563	281
1993	576	288
1994	589	294
1995	603	301
1996	617	308
1997	631	316
1998	645	323
1999	660	330
2000	675	337
2001	691	345
2002	707	354
2003	724	361
2004	740	369
2005	755	377

*Excludes demolition refuse

TABLE VI

SOLID WASTE COMPOSITION

VICTORIA TRANSFER STATION, VISUAL CLASSIFICATION

	% BY VOLUME	
	AS CLASSIFIED	DOMESTIC SEPARATED
Paper, cardboard	20.0	44.5
Wood	9.0	9.0
Metals	5.5	11.0
Glass	0.5	2.5
Plastics, rubber, textiles	3.0	10.5
Construction materials, plaster, concrete	1.5	1.5
Dirt, rubble	2.0	2.5
Foliage	11.5	11.5
Domestic in containers, largely plastic bags	47.0	-
Foodstuffs, wet	-	7.0

Notes - Classification for one complete day
- Domestic separation based on Table 7.

TABLE VII

PERCENTAGE COMPOSITION OF SOLID WASTE BY PHYSICAL SEPARATION

MATERIAL	SAANICH RESIDENTIAL		VICTORIA RESIDENTIAL		VICTORIA COMMERCIAL	
	BY VOLUME	BY WEIGHT	BY VOLUME	BY WEIGHT	BY VOLUME	BY WEIGHT
Paper - loose - cardboard	52.0	32.5	41.0 7.0	28.0 3.5	38.0 28.0	32.5 13.0
Metals, cans	13.5	13.0	15.0	13.5	7.0	10.0
Glass	4.0	14.5	6.0	12.0	7.0	8.0
Wood	Trace	Trace	0.5	0.5	3.0	3.0
Foodstuffs	16.0	31.0	12.5	20.0	6.0	20.0
Rock, dirt, ash	1.0	2.0	8.5	18.0	5.0	10.0
Plastic	8.5	3.5	8.0	3.0	4.0	2.0
Textiles	5.0	3.5	1.5	1.5	2.0	1.5
Loose Density, lb/cu yd	205		226		198	

Notes - Complete separation of a single packer truck for Residential and two open collection trucks combined for Commercial.

TABLE VIII

HARTLAND ROAD INPUT, COMPOSITION BY WEIGHT PERCENT

	1	2	AVERAGE
Paper, cardboard	8.0	4.0	6.0
Metal	4.5	1.5	3.0
Glass	Trace	Trace	Trace
Construction			
- wood	17.5	17.5	17.5
- plaster, non-combustibles	4.5	2.5	3.5
Landscape	4.5	2.5	3.5
Rubble	6.0	1.5	3.5
Demolition	23.5	47.0	35.5
Domestic	31.5	23.5	27.5
Total Input			
Weight (tons)	460.0	580.0	520.0
Volume (cu yd)	1,710.0	2,360.0	2,030.0
Density (lb/cu yd)	540.0	490.0	510.0

Notes - Based on weighing every tenth vehicle regardless of type and visually classifying contents.

- Surveyed October 1973.

For the purposes of this report, the following composition of municipal refuse will be used:

moisture content	-	30% by weight
demolition refuse	-	5% by weight
inorganics, metals, etc.	-	25% by weight

B. Other Combustible Wastes Available to the CRD

1. Demolition and Construction Refuse

Past studies (2) have shown that demolition refuse at times can be a major component of municipal refuse. Table VIII shows an average content of 35.5% by weight during October 1973. This material typically contains about 80% combustible material, primarily in the form of old lumber and construction debris. As such it is a potential source of good fuel.

The wide variations in amount of demolition refuse preclude any accurate estimates of its continuing availability. In addition, the presence of large pieces of masonry and the difficulty of handling long pieces of lumber render it unsuitable for fuel. While much of such refuse now goes to Hartland Road for disposal at the same charge as for domestic refuse, the CRD has intended to require that haulers of demolition waste dispose of it in other ways.

The City of Tacoma presently hammer mills its demolition refuse, using the pulverized waste as cover for domestic refuse. Thus, while it is difficult to handle, it is possible to reduce it to a manageable form. It probably would be simple to separate wood fragments from pulverized masonry even though the cost may be high.

For this study it has been assumed that demolition refuse represents 5% of total waste (based on current records) and can be segregated from other wastes. Its potential heating value will not be included in cogeneration studies.

2. Forest Industry Wastes

Forest products companies within the CRD generate major amounts of wood residues. The major operations (excluding small re-manufacturing plants) generate from 400 to 500 GPU (gravity

packed units) per day, corresponding to 400 to 500 tons of dry wood material. Most of this waste is consumed in plant powerhouses though some is incinerated or landfilled.

Most companies would be pleased to have someone accept their waste provided they had an acceptable alternate fuel. Most now realize that the cost of oil is rising so rapidly that their powerhouses are economic. Should an adequate supply of natural gas be provided, however, some companies might be prepared to relinquish their wood waste for little or no cost.

While wood waste appears to be an attractive additional fuel for a cogeneration plant, there are two reasons for caution in accepting it:

(a) The 20-year forecast for the Lower Mainland and Vancouver Island indicates a shortage of hog fuel. While there is now an excess of waste in most areas and it can be had for transportation costs only, in the future, hog fuel may acquire value as fuel. Thus, there is no assurance of long-term supply nor can it be assumed the residues will be available at no cost.

(b) All wood residues in coastal areas are contaminated with seawater. When burned, a fine salt fume is emitted. This fume is a serious air pollution problem and control equipment is extremely expensive.

For this study, it has been assumed that wood wastes will not form part of the fuel supply.

3. Other Municipal Refuse

(a) Nanaimo Regional District

This area generates some 60 tpd in Nanaimo and a further 15 tpd in the Parksville-Qualicum area. The Region has expressed interest in having the CRD accept its wastes. It is indicated present disposal charges at the landfill in Nanaimo are about $5 per ton, and, presumably, any agency accepting the waste could expect at least this remuneration for disposal. However, the cost of transporting such waste do not look favourable. Trucking without a return haul would probably cost from $12 to $20 per ton on a 100-mile haul. Barging would undoubtedly be lower cost, but the

problems and costs of barge loading and unloading are a deterrent. In addition, barging of refuse would require that the cogeneration plant be located on navigable water to avoid transporting refuse from the barge through city streets.

The possibility of having extra fuel is attractive, particularly in the early stages of operation but transportation problems appear to negate such an advantage.

(b) Cowichan Regional District

The Cowichan Area generates some 20 tons of refuse per day, and, being only 50 miles from Victoria, transfer of the refuse might be economic. At present the refuse is being incinerated in Consumat units. Costs of disposal have not been identified but comparison with similar situations elsewhere suggests that the real cost probably exceeds $15 per ton. At this level of cost, truck transport to Victoria is within reason.

The amount of refuse is so small that it has little effect on the projected cogeneration plant size and cost. In addition, since Cowichan has made an investment in incinerators there probably will be a reluctance to abandon them in favour of transport of refuse to Victoria.

This refuse has not been included in this study.

III. REFUSE DERIVED FUEL IN THE CRD

A. Definition of RDF

Refuse derived fuel (RDF) is the name given to municipal refuse which has been upgraded by removing metal components, inorganic material (glass, grit, etc.) and heavier fractions of the refuse. The remaining material consists primarily of paper, plastics, wood and other light combustible fractions.

Raw refuse can be burned as received in specially designed furnaces which can accommodate high ash content, uneven particle size and variations in moisture content. RDF is made where it is desirable to recover resources (glass, metals) and where a more readily controlled fuel is required.

B. How RDF is Produced

There are many systems for producing RDF. Two basic types are shown in Plates 3 and 4. The principal difference between the two is the insertion of a pre-screening unit to remove inorganics prior to shredding, thereby lowering shredder power requirements and decreasing ash content of the RDF. The weights indicated on the Plates are for dry material and were derived for a refuse source* other than the CRD. Actually the data are very close to being correct for the CRD if the incoming feed is assumed to have a moisture content of 30%.

All plants have a "picking" station on the dumping floor to allow removal of large objects such as refrigerators and water tanks which might cause problems in the system.

A number of improvements to the basic system have been developed. In the ultimate, as demonstrated at the Americology plant in Milwaukee and the Occidental Petroleum plant in San Diego, aluminum and glass can be recovered as separate streams suitable for recycling. Such refinements are justified only where a market for these products exists. Industry has not exhibited marked interest in such raw materials except in specific cases.

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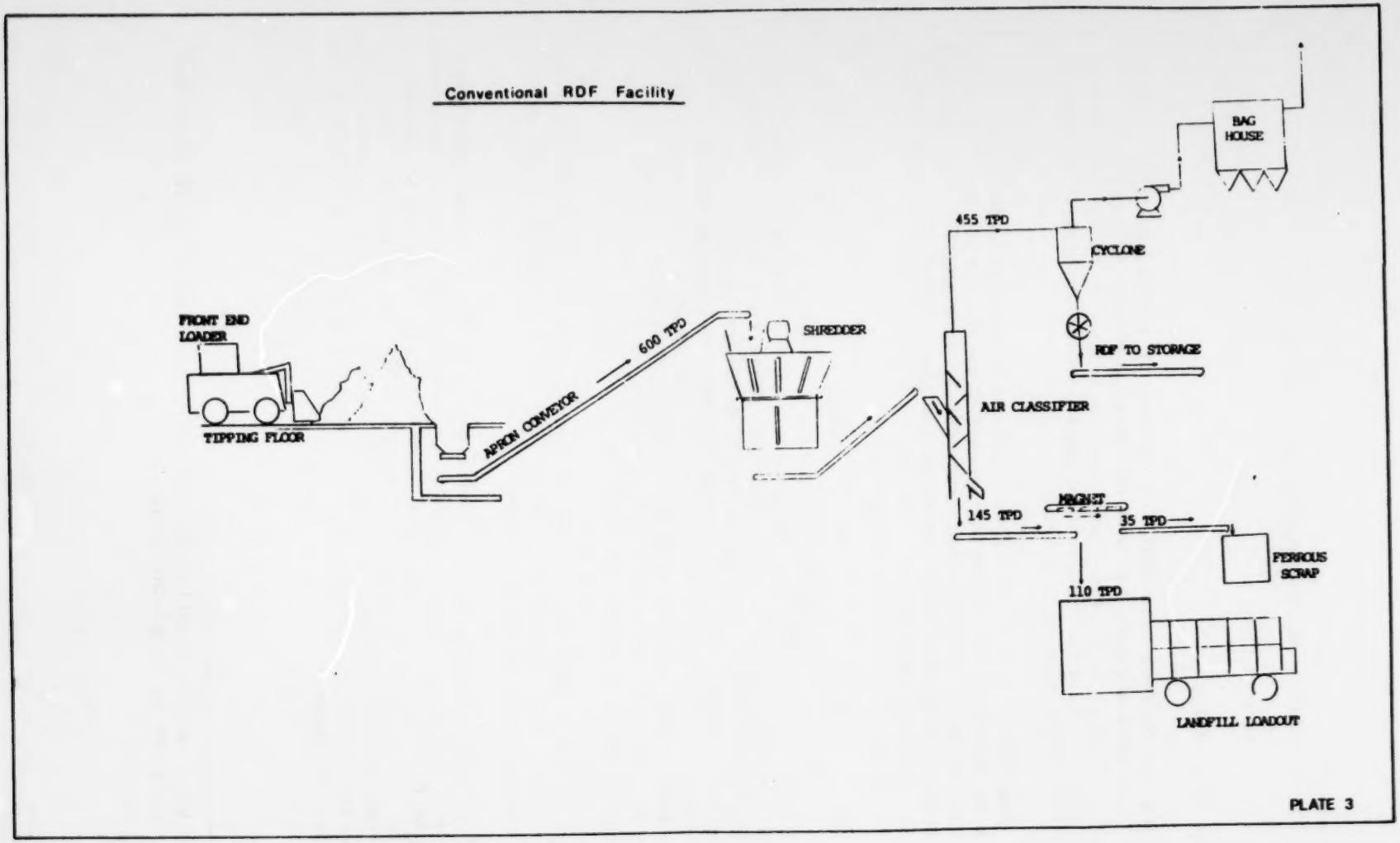
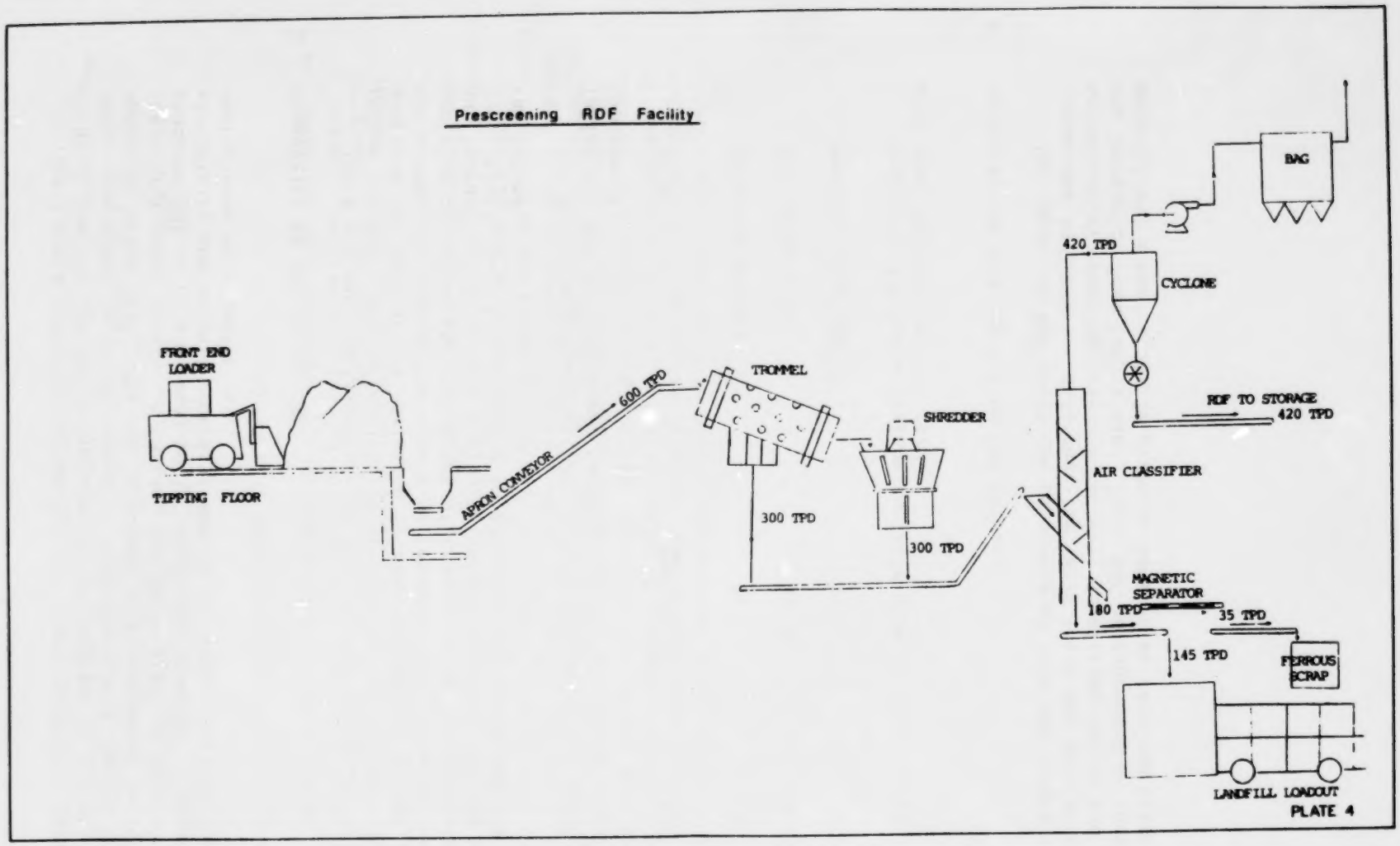
*Data from Omnifuel Gasification Systems Ltd., applicable to CIL Fluid Bed Gasifier Operation at Kingston, Ontario.


Conventional RDF Facility
BAG HOUSE
455 TPD
CYCLONE
FRONT END LOADER
600 TPD
SHREDDER
RDF TO STORAGE
APRON CONVEYOR
AIR CLASSIFIER
TIPPING FLOOR
MAGNET
145 TPD
35 TPD
FERROUS SCRAP
110 TPD
LANDFILL LOADOUT
PLATE 3


Prescreening RDF Facility
BAG
420 TPD
CYCLONE
FRONT END LOADER
TROMMEL
600 TPD
RDF TO STORAGE
420 TPD
SHREDDER
AIR CLASSIFIER
APRON CONVEYOR
TIPPING FLOOR
300 TPD
300 TPD
MAGNETIC SEPARATOR
180 TPD
35 TPD
145 TPD
FERROUS SCRAP
LANDFILL LOADOUT
PLATE 4

There are a number of successful RDF plants presently operating in North America and the technology can be regarded as proven. The Ames, Iowa plant is the prototype of such operations, having been in operation since 1975. The RDF is burned as a supplement to coal in the City's power plant. In Canada, the SWARU plant at Hamilton produces RDF to fire a steam boiler which was intended to generate electricity and to sell process steam in the area. Markets for the energy have developed slowly.

C. Properties of RDF in the CRD

There are many published values for the heating values of both raw refuse and RDF. The variability of as-received waste undoubtedly accounts for much of the variation in reported heating values for it, but a properly treated RDF should be reproducible. Knowing the composition of refuse and the extent of removal of non-combustibles (metals and inorganics) it is possible to calculate the gross heating value of RDF. Similarly, it is possible to calculate the gross heating value of raw refuse.

The following properties have been estimated on the basis of Tables VII and VIII and known heats of combustion for typical refuse components:

ITEM	RAW REFUSE	RDF
Moisture content (%)	30	15
Ash content (%)	25-30	8-16
Heating value (Btu/lb)	4500	7000

Typically RDF has a maximum particle size of about three inches with most material in flat form.

D. Amount of RDF Available from CRD Refuse

The amount of RDF which can be generated from CRD refuse is summarized in Table V. Note that the Table lists dry RDF, which is calculated by removing moisture content, demolition refuse and part of the inorganics from raw refuse. Thus, RDF is expressed as tons of dry material while raw refuse is given as tons of as received material (wet).

This does not affect calculations of potential energy availability because heating value is properly based on dry material content. The actual weight of RDF handled in a plant will be greater than the Table V values by its moisture content but the volume will be the same. The gross heating value is not affected by moisture content but combustion efficiency may be reduced.

E. Potential Recovery of Resources from Refuse

As has been pointed out earlier, in the process of upgrading the fuel value of refuse it is possible to recover metals and glass. Except in unusual situations, the only commodity normally recovered is the ferrous metals group because such metals are readily removed by magnetic separators.

In this study it has been assumed that only ferrous metals will be recovered and that a market for such material exists. The value of steel and iron varies depending on industries which can use such material. At Ames, Iowa, recovered ferrous metal (chiefly tinned cans) is sold for $55 per ton fob buyer's plant. At other disposal plants, recovered ferrous metals are considered to be worth $25 to $35 per ton on site. Since typical refuse may contain from 5 to 7% of ferrous metal, one ton of raw refuse may yield about $1.75 worth of ferrous metal. In this report, to be conservative, a value of $1.00 per ton for resource recovery has been assumed, assigning $0.75 for transport of the metal. This corresponds roughly with the Ames, Iowa experience.

IV. MARKETS FOR ELECTRICAL ENERGY IN THE CRD

A. Potential Purchasers

1. B.C. Hydro

B.C. Hydro is the obvious first choice as a customer because it has a distribution system and because it is short of power on Vancouver Island. Discussions with B.C. Hydro personnel have indicated that Hydro is prepared to purchase power generated in smaller plants, the price to depend on quality of service.

Some of the pertinent matters raised by Hydro are:

(a) Any generating plant connected to Hydro's system must be suitably designed to protect both plant and system, must provide accurate metering and must provide power reliably at required voltage and frequency.

(b) The plant preferably should be close to a substation to minimize connection into the distribution system.

(c) Hydro will buy power on the following general terms:

(i) The CRD will generate to the best of its ability. Hydro will not depend on the facility by demanding a specific load.

(ii) With only one generator, Hydro will pay only for power delivered because a failure puts the plant off line.

(iii) With more than one generator Hydro will make some allowance for the capacitance provided.

(iv) Availability of power is important. If down time is high, Hydro will not pay for capacitance.

2. Industry

The only present industrial user of major amounts of electrical energy is the B.C. Forest Products Ltd. sawmill/plywood plant complex. This plant presently generates a part of its own requirements in its hog-fuel-fired steam plant and purchases the remainder from B.C. Hydro.

It is doubtful this plant could consume all of the energy which would ultimately be generated by a cogeneration plant, so that it cannot be considered as a single preferred market. In addition, steam generation, generated power, purchased power and hog fuel supply are so interrelated at the mill that at present it does not appear to be a suitable customer.

Recent legislation permits a private (other than B.C. Hydro) power plant to sell electrical power to specific large users. However, if these users could not consume all of the power produced, or if they had to have standby links to Hydro service the arrangement might prove to be unattractive.

3. United States Utilities

Utilities in Western United States purchase surplus power from small producers at rates ranging from 20 mills to 50 mills per kWh. These prices reflect the marginal costs of new generating facilities and utilities have been directed by the Federal government to utilize power from any small generator.

The possibility of selling blocks of power to specific US customers using the interconnection between Hydro and US utilities had been considered. Hydro are not prepared to consider any such arrangement.

B. Value of Electric Power

B.C. Hydro are prepared to pay a base rate of 12 mills per kWh for reliable power from a cogeneration plant. In addition, on demonstration of reliability, an extra payment will be made for the capacitance provided. This payment probably would be in the form of a monthly lump sum rather than as an increase in the base rate.

Hydro have indicated the trailing rate on Vancouver Island is 16 mills. They pay 75% of the trailing rate for purchased power.

Hydro state that power costs inflate at the higher limit of the general industry rate. This suggests that any projections for energy costs may fall somewhere between the escalation of values of fossil fuels and the general inflation rate. In the United States, where much electrical energy is generated from fossil fuels, costs have risen sharply. In British Columbia the wealth of hydroelectric power has maintained a lower more stable cost but there are indications that significant increases can be expected in the future.

V. MARKETS FOR STEAM IN THE CRD

A. Basis for Study of Markets

Preliminary calculations as well as experience elsewhere have shown clearly that a cogeneration facility must sell steam as well as electrical energy to be economically feasible. Indeed, many refuse burning facilities sell steam only where a nearby reliable market for all of the steam exists. To illustrate the relative values of steam sold as thermal energy and the same steam converted into electrical energy, consider the following:

- heat from fossil fuel to generate 1 lb of steam at 50 psig (or equivalent hot air) in a boiler operating at 85% efficiency is 1400 Btu;

- No. 2 oil at 170,000 Btu/gal is worth $1.00/gal. In the better turbines 10 lb of steam are needed to generate 1.0 kWh worth $0.012.

The cost of oil used purely as a heat source in a building is, therefore:

$$\frac{\$1.00 \times 1{,}000{,}000}{170{,}000 \times 0.85} = \$6.92 \text{ per million Btu}$$

This does not include labour or capital cost. Therefore steam should be worth at least $6.92 per million Btu when used as an alternative source of heat for a building. If the one million Btu of heat in steam form (at 600 psig and 750F) were converted into electricity, the sales value to a utility would be only $0.74. To a customer the value would, of course, be two to three times greater.

Cogeneration combines the best properties of both markets. Steam is first used to generate electricity and reject steam is sold for thermal energy.

B. Survey of Existing Major Steam Users

1. Commercial - Institutional Users

Commercial and institutional buildings of significant size were visited to obtain the following data:

(a) Whether their heating systems could be converted to make use of a steam service.

(b) Their present annual energy consumption.

(c) Their peak requirement.

(d) Their minimum requirement.

Building owners or managers were contacted for data. All were interested and cooperative and most larger buildings and government agencies had detailed data available.

When monthly and peak values were not available, data were obtained by using degree-day analysis and B.C. Hydro load charts (see Table IX and Figure 3). Recorded data on heat requirements checked reasonably well with calculated requirements and so it has been assumed that the degree-day load-chart method of calculation is acceptable.

Table X summarizes data for the major users. In general the survey has shown the following use pattern:

	January	July
Hotels	14% of annual total	4% of annual total
Offices	16% of annual total	2% of annual total

Exceptions to this are Labatts Brewery which has a constant production requirement and Victoria General Hospital which operates a laundry and has a 6.4% July figure.

Some discretion was used in selecting the buildings. Relatively small buildings in the downtown core were included while similar size buildings further out were not. This was because it is obviously impractical to extend a steam distribution system to small isolated locations.

Some large buildings are listed with zero figures because they have electric systems without a central source which could use steam. These are listed for the sake of completeness. Many electrically heated apartments in peripheral areas have not been listed.

The majority of the buildings listed are heated with light oil as the fuel.

It is interesting to note that electrical heating competes favourably with oil heating in smaller buildings and apartments. Electrical heating can be installed at a lower cost than oil heating, and, at 30 mills per kWh, the cost of electrical energy is only $8.80/million Btu, close to that of oil and probably less likely to inflate rapidly.

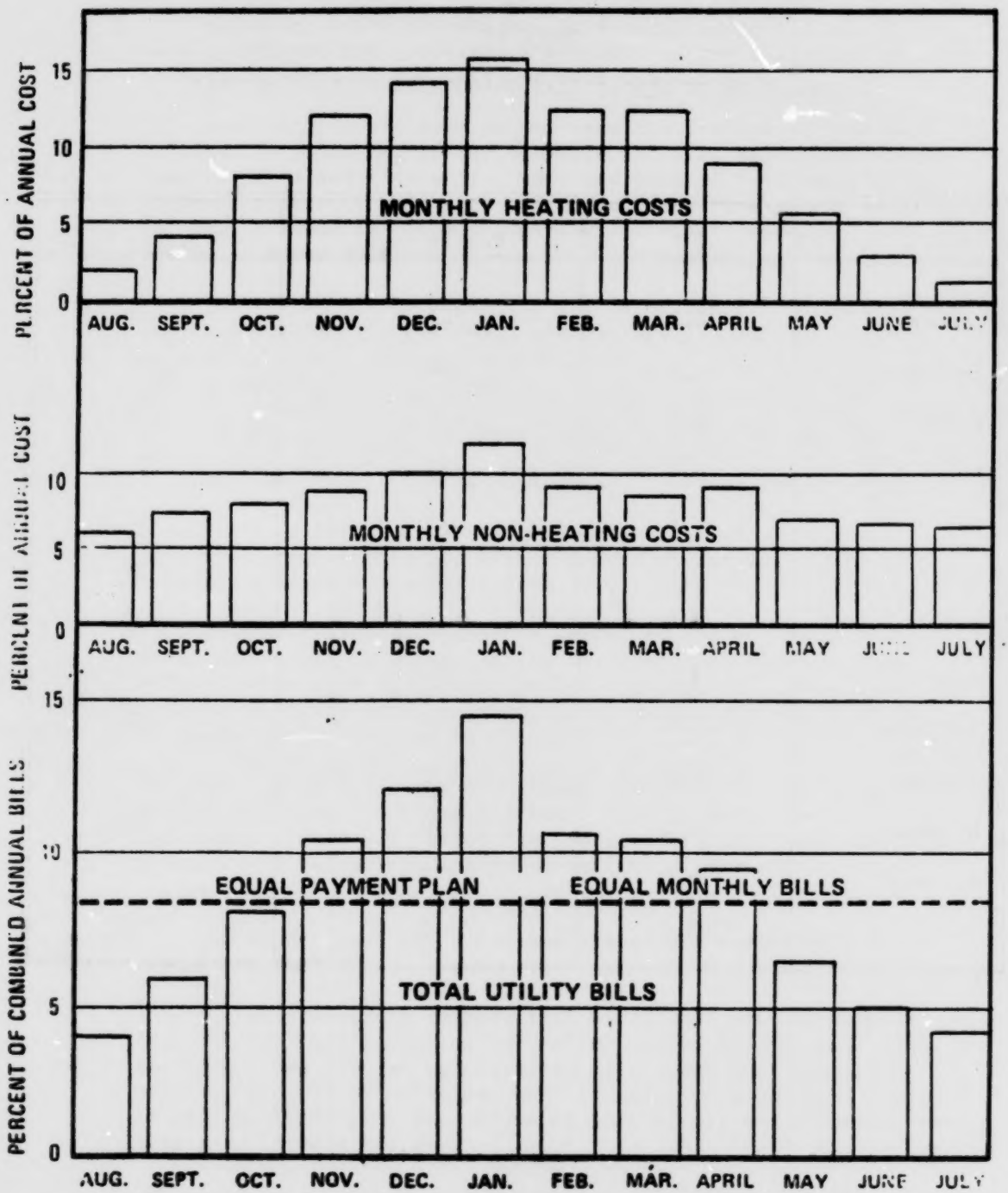
TABLE IX

DISTRIBUTION OF DEGREE DAYS THROUGHOUT YEAR - VICTORIA

	%	F Degree Days	C Degree Days
January	16.0	867	481
February	12.5	676	376
March	12.5	676	376
April	9.0	487	271
May	6.0	325	180
June	3.0	162	90
July	1.0	54	30
August	2.0	108	60
September	4.0	216	120
October	8.0	432	241
November	12.0	649	361
December	14.0	757	421
TOTAL	100.0	5410	3006

FIGURE 3

B.C. HYDRO EQUAL PAYMENT PLAN



The first two charts above illustrate the variations from month to month in heating costs and in the costs of non-heating uses such as lighting and water heating. They are based on an average year.

The third chart combines the first two and also shows the level of the equal monthly payments that would apply under the Equal Payment Plan.

The Equal Payment Plan helps you to avoid large utility bills around the Christmas season by spreading your costs uniformly throughout the year. Ask about it at your local B.C. Hydro office.

TECHNICAL SERVICES DEPT.

TABLE X

POTENTIAL MARKET FOR STEAM, VICTORIA AREA

BUILDING	ANNUAL BTU x 10^6	JULY BTU x 10^6	JANUARY BTU x 10^6	PEAK HOUR BTU X 10^3/HR
Provincial Government				
1. Parliament Buildings	59,500	2,020	8,400	23,400
2. Dogwood Building	2,320	50	350	1,000
3. Waddington Building	8,120	160	1,200	3,350
4. Law Courts	5,800	120	870	2,420
5. Richard Blanshard	8,700	180	1,300	3,600
6. St. Anne's Academy	5,220	105	780	2,170
7. 780 Blanshard	1,740	35	260	725
8. Rithet Building	1,740	35	260	725
City of Victoria				
9. Crystal Pool	14,060	560	1,970	5,470
10. Arena	2,810	50	420	1,170
11. Centennial Square	6,190	125	930	2,580
12. Royal Theatre	2,610	50	390	1,080
Hotels				
13. Empress Hotel	40,820	2,450	5,710	15,850
14. Chateau Victoria	11,600	460	1,620	4,500
15. Executive House	4,200	160	590	1,650
16. Strathcona	3,712	150	520	1,450
17. Royal Olympic Hotel	3,400	140	480	1,340

TABLE X (Continued)

POTENTIAL MARKET FOR STEAM, VICTORIA AREA (Continued)

	ANNUAL BTU x 10^6	JULY BTU x 10^6	JANUARY BTU x 10^6	PEAK HOUR BTU x 10^3/HR
Hotels (Continued)				
18. Harbour Towers	10,100	400	1,400	3,890
19. Laurel Point	0			0
20. Courtyard Inn	2,800	120	390	1,080
Office Buildings				
21. Bank of Commerce	7,356	150	1,180	3,280
22. Royal Bank	2,000	40	320	890
23. Belmont Building	500	0	200	550
24. Wilson Centre	3,250	70	520	1,440
25. International House	4,350	90	720	2,000
26. Bentall Building	4,520	90	730	2,030
27. Montreal Trust	2,500	50	400	1,110
28. Sayward Building	3,100	60	480	1,330
29. Toronto Dominion Bank	2,020	40	320	890
30. Royal Trust	4,200	90	670	1,860
31. Central Building	4,500	90	720	2,000
32. Canada Trust	1,100	20	180	500
33. Yarrow Building	5,200	100	830	2,300

TABLE X (Continued)

POTENTIAL MARKET FOR STEAM, VICTORIA AREA (Continued)

BUILDING	ANNUAL BTU x 10^6	JULY BTU x 10^6	JANUARY BTU x 10^6	PEAK HOUR BTU x 10^3/HR
Hospitals				
34. Victoria General	49,400	3,140	5,610	15,600
35. Royal Jubilee	105,060	4,730	13,930	35,000
36. Mount St. Mary	3,020	120	430	1,190
37. Gorge Road	18,330	750	2,560	7,110
University of Victoria				
38. Clearihue Boiler Pl.	47,600	820	5,700	15,800
39. Commons Boiler Pl.	11,300	0	2,800	7,780
40. McKinnon Boiler Pl.	17,000	640	2,030	5,640
41. Remainder Boiler Pl.	18,000	360	2,880	8,000
Federal Government				
42. Customs	2,320	50	370	1,030
43. Post Office	2,900	60	480	1,330
Department Stores				
44. Eatons	10,820	430	1,510	4,190
45. Bay	9,758	390	1,370	3,800

TABLE X (Continued)

POTENTIAL MARKET FOR STEAM, VICTORIA AREA (Continued)

BUILDING	ANNUAL BTU x 10^6	JULY BTU x 10^6	JANUARY BTU x 10^6	PEAK HOUR BTU x 10^3/HR
Miscellaneous				
46. YM/YWCA	9,512	475	1,046	2,900
47. Crystal Gardens	9,940	400	1,400	3,900
48. Union Club	3,250	130	450	1,250
49. Labatt's Brewery	31,320	2,540	3,130	10,000
50 Harbour Square	0			0
Projections				
Hotel on Songhees Property	10,000	400	1,400	4,000

2. Position of City of Victoria

Mr. J. Sansom, City Engineer, has indicated unofficially that the City would not object to central heat distribution throughout the City. Mr. C.A. Goldie, the underground services engineer for the City focused on the difficulty of running an underground steam line through the core areas. He provided a copy of his report prepared in 1968 when another system was being considered. This is not their official response but it does give some overall idea as to what their concerns may be. The congestion of services at street intersections has increased since 1968 due to the extensive installation of underground electrical and telephone services.

The three significant pages from this report are included here as Figure 4.

3. Discussion with BCBC

It was mentioned that some consideration is being given to burning pelletized wood waste in the Parliament Buildings steam plant. The boilers were originally solid fuel fired and so it is thought that a conversion to wood waste may be feasible.

4. The Department of National Defence, Esquimalt

The base at Esquimalt presently generates steam for heating from oil-fired boilers. Table XI shows data provided from Barton's report (5) which was prepared four years ago. The very low values in July and August appear unprobable because it is known some steam is always used to keep inactive ships free from condensation.

The market is extremely attractive because it is large and is concentrated.

5. B.C. Forest Products Ltd.

This mill offers interesting possibilities for a steam market but the existence of a hog-fuel-fired power plant inhibits action. The plant generates some 125,000 lb/hr of steam under full load. The load has remained at maximum three shifts/day in both sawmill and plywood mill but is low on weekends (kilns only). Thus it might be reasonable to assume a yearly consumption of about 800 million lb of steam.

FIGURE 4

TO: Mr. W. N. Jorgensen

FROM: C. A. Goldie

September 26th, 1968.

RE: PROPOSAL FOR CENTRAL HEATING SYSTEM

The proposal respecting formation of a company to provide a steam heat service in Victoria is at this time very sketchy and indeed is exploratory. No information is given respecting either area or mechanics of distribution other than that the system would employ "low pressure steam" which "is automatically reduced to safe limits by a special valve as it enters the building", and that the area of interest is downtown Victoria with mention of the Wharf Street Renewal area.

Such a general proposal is difficult to evaluate except by voicing a number of equally general queries and comments that appear relevant.

1) Detail is required on pressures and temperatures likely to be employed. How low is "low pressure" that requires reduction to "safe limits"? What are the basic physical requirements such as grade on steam pipes, drainage for condensates, vaults for valves, pipe expansion units or condensate return pumps.

2) What protection is normally afforded against rupture which could occur through (a) weakness or excess pressure
(b) Corrosion
(c) traffic loading
(d) damage caused by subsequent excavation.

Items (a) and (b) should be well taken care of by adherence to standard acceptable practices. Such practice may well also cover items (c) and (d), but it is evident that some form of armour should be required as (i) encasement in concrete - attendant difficulties from expansion and in making connections.
(ii) enclosure in pipe conduit - difficulties in making connections.
(iii) enclosure in conduit with removable lid.

3) Effects of heat loss require consideration. Depending on extent of heat loss and resulting raised ground temperatures, items subject to adverse effects are:-
a) Sidewalk trees
b) Water supply particularly in parallel mains or services
c) Gas services, particularly CI where joint leakage might be promoted.
d) Electrical services employing plastic conduits or insulation.
e) Bituminous road surfaces subject to softening.

4) Conflict with other services severely restricts available space. It is not possible to specify any standard

location for a new service as those existing are not already placed. The downtown area streets commonly contain the following:-

a) Sanitary sewer, generally close to center line and at reasonable depth, usually 8' or more.

b) Storm drain, 8" to 15" one side or other, sometimes both, often shallow 3-6 ft.

c) Water main, 4" to 12" one side or other, sometimes two, approximately 3' cover.

d) Gas main (B. C. Hydro) mostly 4" to 6" one side or other approximately 2' cover normal.

e) Electric ducts (B. C. Hydro) 2' square and larger, 3' or more bury, located both sides of most streets close to curb or in sidewalk.

f) Telephone ducts in street or sidewalk, fairly shallow.

g) Street lighting ducts beneath sidewalk and crossing intersections, shallow.

h) Basement extensions under sidewalks exist on many of the older buildings.

i) Trees are planted on many downtown streets approximately 3' back of curb.

In addition to the above noted mains which run the lengths of streets there are of course many lateral connections from each, in addition to various appurtenances as manholes, valve boxes, junction and transformer vaults, etc.

Typical examples with cross sections are attached. Also attached are separate plans showing distribution of water mains, sewers, storm drains, gas mains, telephone and hydro ducts in the area.

Considering the foregoing it is evident that location of any new mains service in the downtown streets will require individual block by block study. From the point of view of city underground services the streets are already too congested but the additional service might be accommodated if it is demonstrably advantageous.

However, such accommodation must be predicated on a policy that City services, both existing and future have precedence, and that private services will be altered at owners expense to avoid conflict.

Construction of steam lines must necessarily be to accepted standards and suitably enclosed. A buried channel with removable lid in which the lagged steam pipe(s) may be suspended might prove most suitable. (This is said, having no knowledge of steam transmission practice). Such an arrangement would provide:-

a) Armour while maintaining accessibility for service connections

b) Freedom for pipe expansion

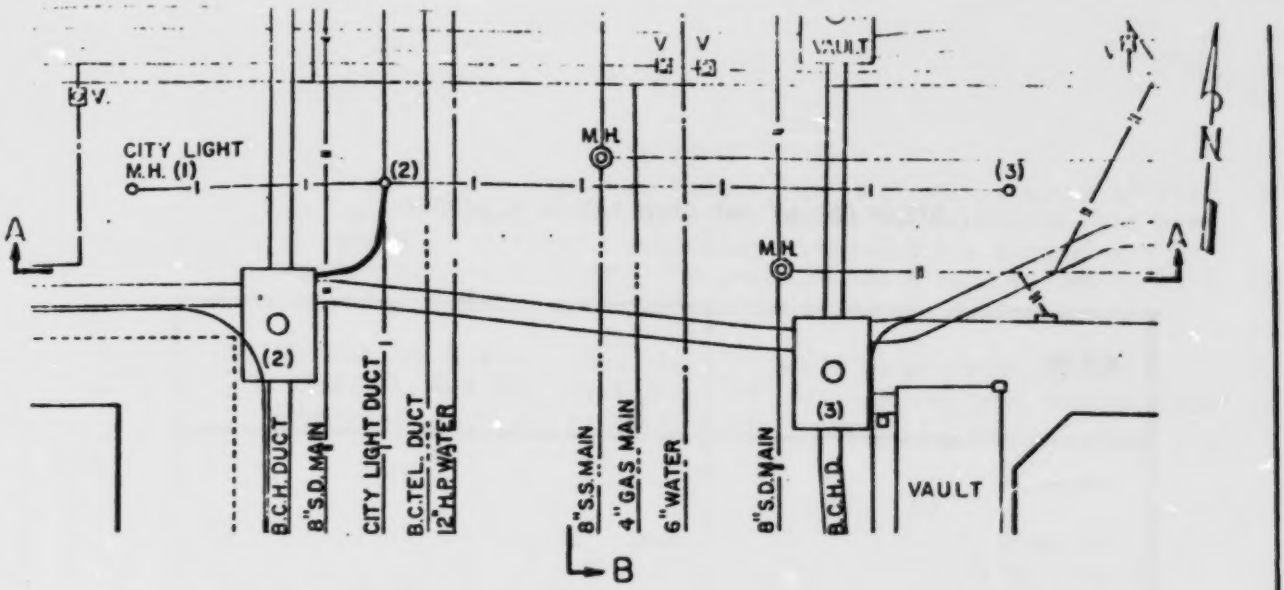
c) Easy recognition

d) Air space around pipe for further insulation and ventilation to junction manholes.

e) Drainage to junction manholes.

f) Controlled escape and easier location of steam leakage.

Service connections might be enclosed in suitable pipe from duct to property line. No steam main should be permitted closer than about 5' (outside distance) to parallel mains or services for water, gas, or electricity. Intersecting lines might be permitted to within 18" of each other. With respect to trees it would seem necesary to require a minimum distance of about 15' to avoid soil heating and drying in the Root area.



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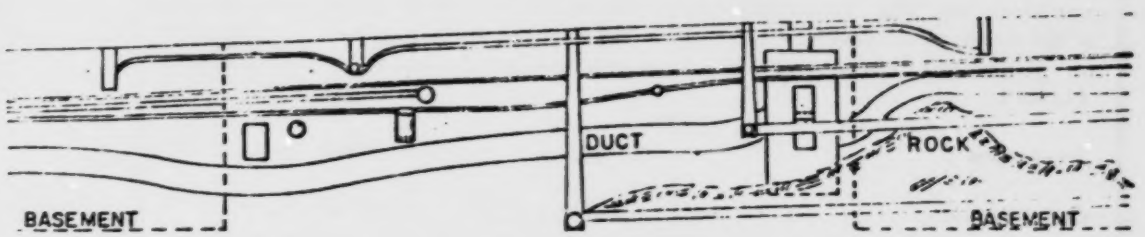


SECTION A-A

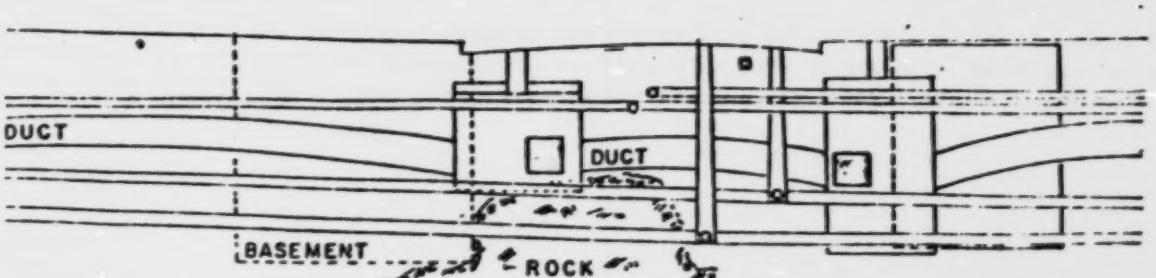


TABLE XI

STEAM USE AT DND FROM BARTON'S REPORT

MONTH	STEAM USE EQUIVALENT OF FUEL CONSUMPTION (million pounds)
January	25.6
February	22.4
March	23.4
April	19.2
May	17.0
June	13.0
July	0.6
August	0
September	10.5
October	18.9
November	21.4
December	26.5
TOTAL	198.5

As has been mentioned before, the mill must dispose of its own wood residues, and, having an operative powerhouse, can burn all waste effectively. Pollution from the boilers remains a problem but the mill may find that the waste is a valuable resource as other sources of energy escalate in price.

It is doubtful that the mill would be prepared to pay current commercial rates for steam because they can develop steam from wood waste at a significantly lower cost.

C. Possible Future Markets for Steam

Any new office building, hotel or institutional building will be a prime market prospect. However, such buildings will have to be located near to "core" areas so that transmission of steam is economically feasible.

Market surveys for a commodity which is not available suffer because the reality is not there to convince a customer. Typically, markets develop when the commodity is available and use patterns may be much different than expected. No predictions have been made for future use of steam because there is no firm basis for doing so.

D. Distribution of Markets in the CRD

Plate 5 shows the location of the steam users listed in Table X. Plate 6 shows the same locations but with building heating loads indicated as Btu/yr x 10^9. It is apparent from the Plates and from data for DND that there are four major market cores:

1. The downtown core including the parliament buildings at about 200 x 10^9 Btu/yr or 200 million lb of steam.

2. The DND area at Esquimalt at 198 x 10^9 Btu/yr or about 198 million lb of steam.

3. The University of Victoria at 94 x 10^9 Btu/yr or about 94 million lb of steam.

4. The Royal Jubilee Hospital area at about 105 x 10^9 Btu/hr or 105 million lb of steam.

The refuse generated by the CRD is capable of yielding about 440 million lb of steam/year, so that the core areas will each use at the most 50% of the total steam generated. The total CRD is capable of

using all of the steam generated but it is impractical to think of widespread steam distribution from one central facility. The practical maximum distance for transporting steam or hot water is not well defined because it depends on the size of the potential user and the difficulty of placing steam mains. The experience of Vancouver Central Heat is interesting. Their original customers were within about 0.75 miles but as more distant large customers have become available, lines have been extended well over one mile. In other cities, central heating lines have been run over two miles.

The lack of one central major steam market leads to the thought that more than one waste burning plant should be considered. It undoubtedly is not appropriate to consider generating electricity at more than one site so that any such plan to dispose of wastes at several sites could contemplate steam sale only.

E. Value of Steam to the User

The value of thermal steam in the CRD relates to the cost of generating steam (or hot air) with fuel oil or natural gas in individual heating. Most commercial and institutional buildings are presently heated with oil. New buildings presumably will have the option of using natural gas, so that the price of gas may control the selling price of steam. It appears that the price of natural gas will be from 70 to 80% of the oil price in the future, but there is no information available on the pricing of natural gas when it reaches Vancouver Island. It may be reasonable to assume Island residents will pay some premium and so a value corresponding to 80% of the oil price has been selected.

It might be argued that electrical energy is a competitor to steam for space heating. The unit costs of thermal energy from electricity and from oil are roughly equal at present when the costs of installation and operation are included. Since Vancouver Island suffers from a shortage of electric power, there should be no immediate pressure from electrical energy as a competitive source of heat in larger buildings.

The price which can be obtained for steam is what the customer can and will pay. If it is assumed steam must displace fuel oil or gas the customer must be convinced that it is less costly to buy steam on demand than to operate a steam or hot water boiler with attendant labour and maintenance. For a new building, a capital cost reduction occurs because a boiler need not be installed. Note here that once a customer has converted to steam purchase from a central plant, that plant is obliged to continue providing steam as required. This implies that a central plant will need a fossil-fueled standby boiler to cover periods of down time for the refuse fired boiler.

The unit cost of operating a small gas- or oil-fired boiler will vary from building to building depending primarily on boiler size. Consider a building requiring 10×10^9 Btu/year for heating. This building will require a boiler capable of peaking at 100% above the average load based on the data of Figure 3. Such a boiler will be about 75 hp generating some 2500 lb/hr of steam. One operator is needed in buildings occupied only during the day (office buildings) and three are needed in buildings always occupied (hotels). Assuming such a boiler installed with controls costs about $75,000 and is amortized over 10 years at 15%, the yearly cost of operation exclusive of fuel is:

Labour, one man	$25,000
Amortization of capital	13,000
Supplies, maintenance	2,000
	$40,000

The approximate cost of heat for this case is the cost of fuel plus cost of operation. Given results for several fuel prices are shown on the following page.

The calculations do not assume gas and oil have equal costs. The table says that if gas is available at $2.94 per 1000 cu ft the annual cost of heating is $74,600. If oil were available at $0.50 per gallon, the cost would be the same.

The calculations are idealized and probably are applicable only to a new building. In an existing building the boiler already exists and probably has been written off.

The calculations do show that a steam price in the range of $7.00 to $10.00 per 1000 lb is reasonable. Energy-from-refuse plants elsewhere have tended to keep their steam costs about 10% below competitive fossil-fuel-produced steam so that there is a definite incentive to purchase steam.

Cost of Fuel					
$ per gal for oil	0.50	0.60	0.80	0.90	1.00
$ per 1000 cu ft for gas*	2.94	3.53	4.71	5.29	5.28
Annual Cost of Fuel ($)	34,602	41,522	55,363	62,283	69,204
Total Yearly Cost ($)	74,600	81,522	95,363	102,283	109,204
Cost per Equivalent ** 1000 lb of Steam ($)	7.60	8.31	9.72	10.43	11.13
Cost per 10^6 Btu delivered ($)	7.46	8.15	9.53	10.23	10.92

*Based on 170,000 Btu per gallon for oil and 1,000 Btu per cu ft for natural gas. Assumes equal efficiency of burning (85%).

**Assumes steam delivered contains 1,190 Btu per lb.

PART II - STUDY OF COGENERATION SCHEMES FOR THE CRD

I. BASIS FOR ANALYSIS OF FEASIBILITY OF COGENERATION

The basic materials and energy flow scheme used for determining the economic viability of cogeneration in the CRD is shown in Figure 4. The components of the scheme are:

1. Delivery of refuse by municipal and contractors trucks to the RDF plant or to the landfill if the RDF plant or boiler plant is inoperative.

2. Treatment of refuse in the RDF plant to yield:

   (a) Upgraded fuel for the boiler plant.

   (b) Reclaimed metal (ferrous in this case) for sale.

   (c) Non-combustible material to the landfill.

3. Generation of steam in the boiler house:

   (a) Steam goes to the turbogenerators.

   (b) Ash to the landfill.

4. Operation of the turbogenerator to produce:

   (a) Electricity.

   (b) Low-pressure turbine reject steam for district heating.

5. Operation of a landfill to provide for disposal of refuse when the RDF and boiler plant are inoperative and to accept non-combustibles and ash.

The existence of a landfill is vital to the success of any energy-from-refuse scheme. It must be capable of disposing of all refuse when the boiler or RDF plant is inoperative and of accepting non-combustibles from the RDF plant and ash from the boiler plant on a continuing basis. Thus, implementation of cogeneration does not eliminate a landfill, it merely reduces filling costs and prolongs fill life.

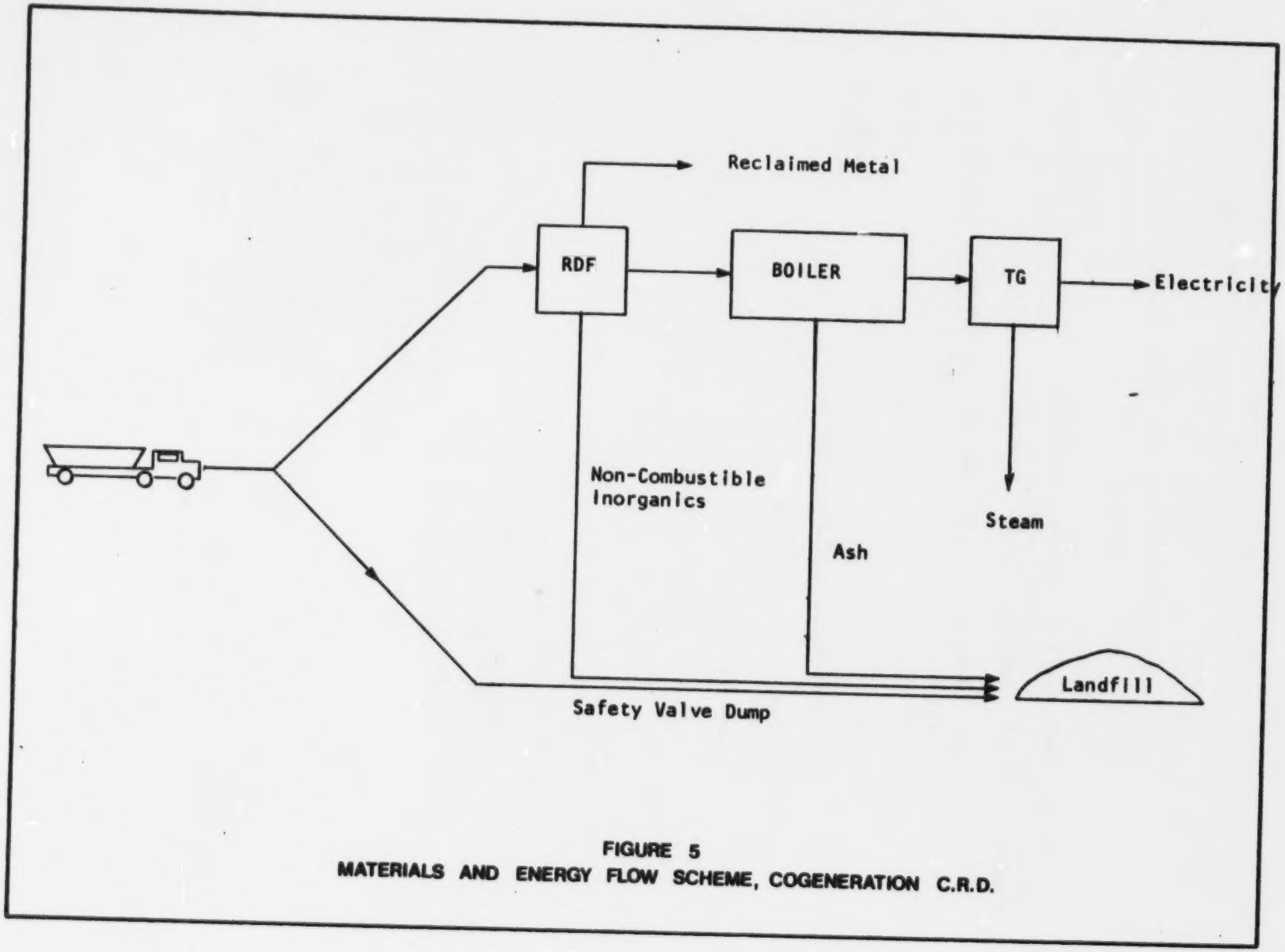


FIGURE 5
MATERIALS AND ENERGY FLOW SCHEME, COGENERATION C.R.D.

Three locations for the cogeneration plant have been selected to serve specific markets:

- downtown core area to serve the government complex, the Empress Hotel and other nearby buildings;
- the University of Victoria to serve all University buildings;
- a site in Colwood directly opposite DND to serve that area.

These sites are not necessarily the only suitable sites but each offers certain advantages which are worthwhile including in assessment of economics.

The evaluation study has a number of objectives:

1. To establish whether or not cogeneration is economic for the CRD given the amount of refuse and probable markets for energy.
2. To establish the sensitivity of economics to capital costs, to operating costs and to value of energy produced and sold.
3. To establish the effect of senior government grants on feasibility of cogeneration.
4. To develop a format suitable for evaluating cogeneration schemes in areas other than the CRD as well as in the CRD.

II. RDF FACILITY

A. Location of Facility

It has been assumed in this study that the RDF facility will be located adjacent to the boiler plant. This arrangement avoids transport of RDF other than by conventional conveyors. The plant could be located at some remote site convenient for all refuse haulers and RDF could be trucked to the boiler plant. The disadvantages of such an arrangement are:

- the RDF tends to be fluffy and blows readily so that compactor trucks or pelletized fuel would be needed;
- the boiler plant would require addition of a fuel storage and reclaim area to accept RDF trucked in.

The land area required for an RDF plant operated in conjunction with a powerhouse is about 2-1/2 acres. If the RDF plant were located separately, an area of at least 4 acres would be needed to provide space for trucks and storage.

B. Operation of the RDF Plant

Because refuse is delivered for five days of each week, two options are open:

- store raw refuse and operate the RDF plant seven days/wk, minimizing the storage of RDF;
- process refuse as it arrives on a five-day basis and store RDF.

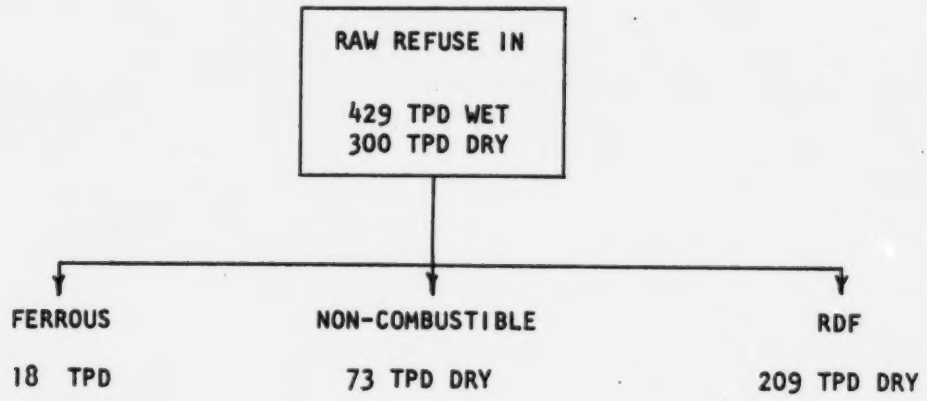
The first option has been selected because some storage capacity is required in any event to smooth out peak deliveries.

An RDF storage bin capable of holding about one-day's production is necessary to provide fuel during hours when the RDF plant does not operate. Briquetting of refuse is not contemplated.

Two-shift operation will become necessary somewhere about 1995 when daily refuse tonnage exceeds 600 tons. Actually, because of peak loads the date may have to be advanced.

C. Plant Material Balance

The material balance for the plant for 1980 tonnage is given below:



Moisture in raw refuse is lost during processing and some appears in the RDF and non-combustible fractions. The RDF typically has an ash content of about 8% though experience has shown a considerable variation in levels. The ferrous metal will have little moisture. The non-combustibles will probably be at about 10% moisture content and the RDF from 15 to 25%.

D. Process Description

For this study a process scheme using prescreening has been selected because it reduces power consumption and decreases ash levels in the product. The process is more expensive than conventional technology because of extra equipment.

Plate 5 shows the flow scheme. Waste from the tipping floor is pushed into a pit conveyor by means of front-end loaders. The flow rate of the refuse is controlled by varying the speed of the pit conveyor which dumps the waste onto an inclined conveyor which in turn directs it to a trommel. This device is a rotating drum, perforated with 4-3/4-inch holes through which glass and can stock will pass. The trommel is also fitted with lifters to pick up and drop the garbage bags.

The undersize from the trommel which contains over 90% of the glass is conveyed to the No. 1 air classifier. The oversize fraction is diverted to a shredder with a shearing action. After size reduction the refuse is fed to the No. 2 air classifier. The lights from the two clarifiers are collected in cyclones and conveyed to storage or boilers. Classifier heavies from Units 1 and 2 are fed through a magnetic separator before being shipped to landfill. The ferrous material is separated and collected for sale.

E. Manpower Requirements

Tipping Floor	-	3
Control Room	-	2
Labourers	-	2
RDF Storage and Recovery	-	1
Supervision	-	1
Total in Plant	-	9

This force will be required throughout the year so that 9 x 365 = 3285 man days of labour are needed per year. When double shifting occurs this number will be doubled. It is assumed that it will not be feasible to have personnel on call at hourly rates.

F. Power Requirements

Total installed power including conveyors and bins for RDF will be 1000 hp.

G. Capital Costs

1. Specific Equipment

	EQUIPMENT PRICE	INSTALLED COST
Pit Conveyor	90,000	135,000
Inclined Conveyor	70,000	105,000
Trommel	220,000	290,000

	EQUIPMENT PRICE	INSTALLED COST
Shredder Conveyor	25,000	37,000
Trommel under Conveyor	15,000	22,000
Air Classifier No. 1 Conveyor	30,000	42,000
No. 1 Air Classifier	250,000	350,000
Heavies Conveyor	10,000	15,000
Shredder	350,000	490,000
Shredder Outflow Conveyor	25,000	37,000
Air Classifier No. 2 Conveyor	25,000	37,000
Air Classifier No. 2	250,000	350,000
Heavies Conveyor	10,000	15,000
Magnetic Separator	45,000	65,000
RDF Conveyor	20,000	30,000
Baghouse for Building Air Control	90,000	120,000
Ventilating Fans	30,000	45,000
RDF Storage Bin, 4000 cu yd	275,000	325,000
RDF Conveyor to Powerhouse	10,000	15,000
	1,840,000	2,525,000

2. Building and Utilities

Building must contain a tipping floor/storage area large enough to hold two day's refuse delivery, or up to 700 TPD. The building will be modular steel appropriately painted and the refuse delivery area will be totally enclosed,

	(a) Cost of building and services		$1,300,000
	(b) Foundations for machinery		200,000
			$1,500,000
3.	Engineering fee for design and supervision		450,000
4.	Contingency to cover contractor's profit, start-up costs, etc.		1,000,000
5.	Total cost		5,475,000

H. Annual Operating Costs

1.	Labour		
	(a) One shift on full time		$271,000
	(b) Two shifts on, one full time other part time (after 1995)		$475,600
	(c) Overhead on labour at 35%	1980	$108,400
		1995	166,500
2.	Power - included in powerhouse load		
3.	Maintenance - materials and labour	-	$2.00/ton throughput
4.	Supplies and miscellaneous including taxes, insurance, etc.		$100,000
5.	Disposal of non-combustibles and ash to landfill		$10/ton of material

III. STEAM PLANT AND TURBOGENERATORS

A. Basic Design by Integ Ltd.

The boiler and turbogenerator plant design is contained in Integ's Report which is attached as Appendix I.

B. Alterations and Additions to the Integ Design

Since the Integ report was submitted, several changes in concept have occurred and further operating data on RDF-fueled boilers have become available. The principal changes are presented below.

1. Reliability of Boiler

Integ has suggested a 77% reliability factor for a boiler fired with RDF, based on experience with boilers burning whole garbage. This value agrees in general with data for large coal-fired boilers. However, data from utilities in the United States firing well prepared RDF indicate less operating problems than are encountered with hog fuel boilers. Possibly the discrepancy results from definition of reliability. For example, the boiler itself may run well but auxiliary components may fail and so the plant is unreliable even though the boiler itself poses no problems.

For those days when the boiler plant is inoperative the standby boiler must operate on oil or natural gas and waste must be taken to the landfill. For short shutdowns waste can be stockpiled in the RDF plant receiving area which will have two to three days capacity.

The turbogenerator reliability has not been changed. This reliability is not critical to overall operation success because refuse can be burned and steam produced even if electricity is not produced.

2. Standby Fuel

Integ have assumed fuel oil for standby. If natural gas is delivered to Vancouver Island it will be a preferred standby fuel because of its ease of use and presumed lower price.

3. Power Use in the RDF Plant

Integ have quoted a power use of 2100 hp with a load factor of 75%. This figure was based on data for a comparable sized plant

at Madison, Wisconsin. Earlier in this report under "RDF" facility the power was indicated to be 1000 hp based on Omnifuel Gasification Systems Ltd. predictions. The difference results from the lower power needed in the plant proposed by Omnifuel. A credit for 1000 hp has been applied to Integ's operating costs.

4. Size of Standby Boiler

Integ have sized the standby boiler for 220,000 lb per hr of steam at 600 psig and 750F. In fact, the steam sold for heating is estimated at 50,000 lb per hour and probably would not grow beyond 100,000 lb per hr. There is no requirement that the standby boiler provide steam for electrical generation, and, indeed, the power so generated would be very expensive.

Thus, the standby boiler is over-sized by 100%. The extra capital cost incurred by the increased size and the high pressure rating is not critical in later cost analyses, but the cost of standby fuel is a significant item in costing plant operations. In economic analyses the cost of the standby boiler and auxiliaries has been reduced to $1,250,000 from $1,760,000.

This exercise becomes further complicated when two RDF boilers are installed and the reliability of steam production from RDF is increased. The probability of both boilers being out of service at one time is low, and scheduled maintenance periods can be staggered. The first boiler installed will have a capacity of some 400 TPD of RDF while the second will be sized to 200 TPD. The 400 TPD apparently should be able to handle all mean RDF production through the year 2008 but because of variations in refuse flow from day to day and throughout the year, an increase of 32% above average has been provided. This 400 TPD boiler will handle all refuse through 1996 approximately and even in 2005 will handle about 80% of the peak load. Thus when two boilers are installed the reliability of the system is increased markedly, and it is unlikely the system would ever be reduced to less than 40% capacity.

C. Production of Steam

Integ in their Report (Appendix II) have calculated steam and electric power generation for various conditions. There are several matters requiring clarification in steam development and standby fuel. Table XII summarizes steam production at the proposed plant. The calculations are based on:

TABLE XII

SUMMARY OF STEAM PRODUCTION

YEAR	QUANTITY OF RDF (tpd)		STEAM GENERATED AT 600 PSIG AND 750 F (1000 lb per hr)		HEAT AVAILABLE IN REJECT STEAM FOR THERMAL USE* (million Btu per hr)	
	mean	minimum	mean	minimum	mean	minimum
1984	234	159	85	57.8	101.2	68.8
1986	245	167	89	60.5	106.0	72.0
1988	257	175	93.3	63.4	111.1	75.5
1990	269	183	97.7	66.4	116.3	79.1
1992	281	191	102.1	69.4	121.6	82.7
1994	294	200	106.8	72.6	127.1	86.4
1996	308	209	111.9	76.1	133.2	90.6
1998	323	220	117.3	79.8	139.7	95.0
2000	337	229	122.4	83.2	145.7	99.1
2002	354	241	128.6	87.4	153.1	104.1
2004	369	251	134	91.1	159.6	108.5
2006	386	262	140.2	95.3	167.0	113.5
2008	404	275	146.7	99.8	174.7	118.9

*16% of mass of steam generated is assumed to be used for deaerating and heating condensate and feedwater.

TABLE XIII

EFFECT OF STEAM SALE ON ELECTRICAL GENERATION

CASE	TOTAL STEAM GEN 600 + 750 (M lb/hr)	TOTAL BTU GENERATED (MM Btu/hr)	STEAM TO DEAER. AT 40 PSIG* (M lb/hr)	BTU TO DEAER. (MM/Btu/hr)	STEAM TO CONDENSER 0 PSIG (M lb/hr)	BTU TO CONDENSER (MM Btu/hr)	STEAM TO SALE 40 PSIG (M lb/hr)	BTU TO SALE GROSS (MM Btu/hr)	ELECTRIC GENER. (kW)	NET BTU SOLD WITH 10% HEAT LOSS (MM Btu/hr)
YEAR 1 (1984)										
No steam sold	85	117	14	17	71	73.6	-	-	7,390	-
50% sold	85	117	14	17	35.5	36.8	35.5	43.2	5,600	38.9
Max sold	85	117	14	17	-	-	71.0	86.4	3,810	77.8
25% sold	85	117	14	17	53.2	55.2	17.7	21.5	6,485	19.3
YEAR 20 (2014)										
No steam sold	169	232	27	32.8	142.0	147.2	-	-	14,733	-
50% sold	169	232	27	32.8	71.0	73.6	71.0	86.4	11,156	77.8
25% sold	169	232	27	23.8	106.5	110.4	35.5	43.2	12,945	38.9

*For simplicity assumed to be the same for any condition of steam sale.

- RDF values from Part I, Section II;

- RDF heating value of 7000 Btu per day lb;

- steam generated at 600 psig and 750F with an enthalpy of 1378 Btu per lb, and return of condensate with an enthalpy of 256 Btu per lb, leaving a net heat requirement of 1122 Btu per lb of steam;

- the variation in waste delivery is assumed to be ± 32%, probably a conservative figure;

- steam production is 8,800 lb per ton of RDF.

Since RDF grows at 2.3% per year both mean and minimum amounts of steam also grow at 2.3% per year. Thus mean steam production is expressed at any time by:

$$Q_n = 85(1.023)^n$$

where Q_n = thousands of pounds of steam producted per hour, n years after 1984.

The heat in the steam generated at 600 psig and 750F obviously will not be totally available for thermal use after passing through the turbines. The last two columns of Table XII show equivalent amounts of heat available for thermal purposes in the form of low pressure steam, based on enthalpy of 1217 Btu per lb of steam (slight superheat retained).

Initial projections indicate that not all of the steam can be sold. Nevertheless, a potential problem can arise when the boiler plant is operating at minimum load and there are peak demands for steam. It is possible the RDF boiler may not be able to meet the peak demands, which may be nearly double the mean load. Typically the situation might occur in winter when waste generation in the CRD is at its lowest and heating demands will peak. The standby boiler is available for these high demand periods and will provide any extra heat needed.

No problems are anticipated until the steam thermal load rises to well above 20,000 lb per hr (approximately 25 million Btu per hr).

D. Production of Electricity

Integ have presented estimates of electrical energy production in their plant. It is important to recognize that maximum electrical energy is developed when no thermal steam is sold and the turbogenerators operate with the condensers accepting all steam. As reject steam is required for sale, the amount of electrical energy developed decreases.

It is emphasized that when the RDF boiler is shut down, the standby fossil fuel boiler will not produce steam for electrical energy generation. It will produce only thermal steam at low pressure.

To illustrate the effect of steam sale on electrical generation, the data of Table XIII have been developed for the years 1984 and 2014. It will be observed that, while electrical generation is affected by sale of reject steam at 40 psig, the effect is not major until such sale approaches 35,000 lb per hr, a level which is unlikely to be reached in the CRD for some time. It is equally important to recognize that sale of steam is an aim to be achieved at all times at the cost of decrease in electrical energy generation. The value of steam compared to the value of electricity derived from steam has been discussed earlier.

The relationship between steam generation, sale of steam and electrical generation is derived as shown below:

1. Performance of Turbogenerators

   (a) For steam rejected at 40 psig - 22.3 lb steam per kWh

   (b) For steam directly to condensers 10.5 lb steam per kWh

2. Steam generated per hour

$$\frac{RDF}{24} \times 8{,}800 \text{ lb per hr}$$

or $$\frac{234(1.023)^n}{24} \times 8{,}800 = 85{,}800(1.023)^n \text{ lb per hr}$$

where 234 is mean daily RDF production in 1984 and "n" is the year starting with 1984 as the base.

3. Steam to Deaerator

$$0.16 \times \frac{RDF}{24} \times 8{,}800 \quad \text{or} \quad 13.728\ (1.023)^n$$

4. Steam Sold

   Define as "Q" lb per hr mean throughout year.

   "Q" may be defined as an initial value plus a yearly increase decided upon when the market area is analyzed.

5. Steam condensed

$$= \text{Item 2} - \text{Item 3} - \text{Item 4}$$

$$= 85{,}800(1.023)^n - 13.728(1.023)^n - Q$$

$$= 72{,}072(1.023)^n - Q$$

6. Electricity generated (expressed as KVA)

$$= \frac{\text{Item 3}}{22.3} + \frac{\text{Item 4}}{22.3} + \frac{\text{Item 5}}{10.5}$$

$$= \frac{13.728(1.023)^n}{22.3} + \frac{Q}{22.3} + \frac{72.072(1.023)^n - Q}{10.5}$$

$$= 7479(1.023)^n - 0.0504\,Q$$

Thus if a relationship for Q as a function of time is obtained, the amount of electrical energy developed in any year, "n", can be calculated.

The value of electricity in any year after 1984 is derived from the combined reliabilities of boiler and turbogenerator and the escalating value of electrical energy (assumed to be 2% per year, real).

The value in any year expressed as dollars is:

$$[7479(1.023)^n - 0.0504\,Q] \times 24 \times 365 \times 0.94 \times 0.98 \times 0.0147(1.02)^n$$

or $887{,}145(1.046)^n - 5.98\,Q(1.02)^n$

It is seen that the second term is small until Q rises to about 30,000 lb per hr, and for rough estimation of electrical energy revenue, the first term can be used.

IV. STEAM DISTRIBUTION SYSTEMS

D.W. Thomson Consultants Ltd. have studied piping layouts and costs for distributing heating steam from three plant sites. These sites were selected as offering concentrated steam loads with space for plant construction.

As work progressed in evaluating the economic feasibility of the cogeneration system, it became obvious that the initial systems would have to be expanded to increase steam sale. As will be seen later, the feasibility of cogeneration depends on steam sale, and any investment within reason which increases steam use is justified.

The various steam distribution systems are described in detail in the accompanying report by Richard J. Brewer & Associates Ltd. entitled "Financial Analysis and Economic Evaluation of the Concept of Cogeneration for the Victoria Metropolitan Area." For convenience the systems are summarized on the following page.

It can be seen that steam distribution systems can be laid out in any way desired. The systems selected for closer analysis were chosen to demonstrate the effects of volume of steam sold and cost of installation.

In general, in the downtown area two sites for the cogeneration have been considered, one at the site of the present powerhouse for the Parliament complex, and one at the vacant land near Pandora and Government Streets. The two other sites at the University of Victoria and at Colwood have not been located precisely because availability of space is not clear at this time.

The question of how far steam or hot water can be transported is not readily answered. There are central heating plants in Europe in which lines run for more than three miles, but such long runs are feasible only where the market at the end is sufficiently large to justify construction of the line.

It must be recognized that the steam distribution systems described are not based on confirmed purchases of steam, but, rather, on what appear to be logical purchasers. There are other potential users, but they are either small or remote.

SUMMARY OF STEAM DISTRIBUTION SYSTEMS

STEAM DISTRIBUTION SYSTEM	INSTALLED COST	STEAM SOLD (lb per hr)
SYSTEM I Parliament, Empress, Victoria General, Crystal Gardens	$ 2,700,000	17,000
SYSTEM II University of Victoria	1,800,000	9,800
SYSTEM III Department of National Defence	3,000,000	20,800
SYSTEM A System I + downtown area + Labatts	7,500,000	25,000
SYSTEM B Same as System A with spur lines on Herald, Pandora, Courtney, View, Fort and Burdett	13,900,000	35,000
SYSTEM C Provides steam to Royal Jubilee, Crystal Pool, Arena and Labatts	8,200,000	16,000
SYSTEM D Combination of Systems A and C covering downtown area and Royal Jubilee	15,700,000	39,100
SYSTEM E Combination of Systems B and C covering downtown almost totally, Royal Jubilee, Arena and Crystal Pool	22,100,000	47,500

V. BASES FOR EVALUATING ECONOMICS OF COGENERATION

A. Method of Expressing Economics

Consideration of cogeneration for the CRD was prompted by the need for a long-term scheme for disposing of municipal refuse. It was hoped that cogeneration (or some other form of energy recovery) would provide a technically and economically feasible alternative to the present practice of landfilling. Accordingly economic data will be provided in two ways:

1. Net Cost or Profit of Operation per Year

$$\text{net cost} = \text{total operating cost} - \text{income from energy and resource sale}$$

2. Cost of Disposal of Refuse

$$\text{cost of disposal} = \frac{\text{total operating cost} - \text{income from energy and resource sale}}{\text{annual tons of refuse}}$$

Since annual disposal costs as $/ton will decrease with time, such costs will be presented as:

- dollars per ton of refuse in each year and total yearly cost;
- accumulated total cost of disposal up to any year in the 25-year period.

B. Basis for Economic Calculations

1. Quantity of Refuse

Table XIII summarizes quantities of raw refuse, RDF, non-combustibles and boiler ash projected to 2005.

2. Procedures Used for Analysis

(a) Base Time

All economic calculations are made on the basis of 1981 dollars. All costs, sale prices, etc. are converted back to 1981 having due regard for inflation, true cost charges over and below inflation, etc.

TABLE XIV

SUMMARY OF MATERIAL TO BE HANDLED

YEAR	AVERAGE REFUSE GENERATION (TPD AS REC'D)	EQUIVALENT RDF (TPD DRY)	NON-COMBUSTIBLES (TPD WET)*	BOILER ASH (TPD)	FERROUS (TPD)**
1979	419	209	78	17	18
1980	429	214	80	17	18
1981	438	219	82	17	18
1982	449	224	84	18	19
1983	459	229	86	18	19
1984	469	234	88	18	19
1985	480	240	90	19	20
1986	491	245	92	19	20
1987	503	251	94	20	21
1988	514	257	96	20	21
1989	526	263	98	21	22
1990	538	269	101	21	22
1991	550	275	103	22	23
1992	563	281	105	22	23
1993	576	288	107	23	24
1994	589	294	110	23	24
1995	603	301	113	24	25
1996	617	308	115	24	25
1997	631	316	118	25	26
1998	645	323	121	25	26
1999	660	330	124	26	27
2000	675	337	126	27	28
2001	691	345	129	27	29
2002	707	354	132	28	30
2003	724	361	135	29	31
2004	740	369	138	29	31
2005	755	377	141	30	32

*At approximately 10% wet basis moisture content.
**Assumed to be dry.

Note: Refuse generation does not equal the sum of the component parts here because RDF is expressed as dry material and some moisture is lost in processing.

(b) Amortization of Capital Investment

It is assumed investment is depreciated over 25 years. Equipment added in 1995 is also assumed to depreciate over 25 years. Yearly payments are based on repayment of a loan equal to the capital investment over 25 years.

Because capital repayment is based on 1981 dollars but will be paid in inflated dollars, the actual payment will be decreased each year by the amount of inflation.

(c) Interest Rate

Interest is assumed to remain constant at 15% throughout the term.

(d) Value of Electric Power

It is assumed power will escalate at 2% above the average inflation rate.

B.C. Hydro have indicated a base price of 12 mills per kWh as a reasonable starting point. Credits for load factor, number of turbines, etc. might allow this price to be increased to 13 mills. Accordingly, starting with 1980, the price of electricity will be 13 mills and it will escalate at 2% per year thereafter.

(e) Inflation Rate

The inflation rate is assumed to be 12% per year over the term.

(f) Value of Ferrous Metals

The value of ferrous metal recovered is assumed to be $1.00 (1980) per ton of raw refuse. Note that quantity of metal will increase at 2.3% per year, and that value of metal increases at 1% (real) per year.

(g) Labour Costs

It is assumed labour costs will follow inflation trends, and, because all costs are brought back to 1981 dollars, these costs will remain constant throughout the 25 years. It is recognized that merit raises will occur but these are of second-order importance in the analysis.

(h) Maintenance Costs

Maintenance costs are assumed to increase at 2% (real) per year.

In the RDF plant maintenance costs are tied directly to refuse throughput ($/ton). In the power plant maintenance will increase in 1995 when the second boiler and third turbo-generator are brought on line. The increase will be roughly proportional to capital investment.

(i) Fuel Cost

The current costs of oil in Victoria are:

- heating oil (light) $0.973/Imp gal
- heating oil (heavy) $0.941/Imp gal

Oil is assumed to escalate at 5% per year above normal inflation.

The cost of natural gas when it reaches Victoria is not known. If it is assumed it is held at 80% of light oil value, the sales price of gas now would be $4.58 per million Btu. The escalation of natural gas cost is assumed to be 5% per year above normal inflation.

(j) Value of Steam for Heating

Steam used for heating in the CRD has a value dependent on the fossil fuel it replaces. Assuming oil is the competitive fuel, the value of steam including an 85% conversion efficiency ranges from $9.13 to $9.44 per 1000 lb (approximately 1.1 million Btu). If natural gas is the preferred fossil fuel, the value of steam will be in the order of $7.50 per 1000 lb in 1980.

C. Basis for Costing

1. Capital Costs (1981 $)

(a) Original Boiler Plant

1980 base price	$ 19,990,000
Add 25% for engineering, legal, profits, etc.	4,997,000
	$ 24,987,000

	1981 base price	$ 27,986,000	
	Add interim financing	1,679,000	
	Total Capital 1981	$ 29,665,000	$ 29,665,000
(b)	Additions to Boiler Plant in 1995-96		
	1980 price	$ 7,120,000	
	Adjust to 1981	7,974,000	$ 7,974,000
(c)	RDF Plant		
	1980 price	$ 5,475,000	
	1981 price	6,132,000	$ 6,132,000
(d)	Power Line to Substation		
	1980 price	$ 300,000	
	1981 price	336,000	$ 336,000
(e)	Steam Distribution Systems (1981 prices given)		
	System I, downtown		$ 2,650,000
	System II, university		1,750,000
	System III, DND		3,000,000
	System A		7,500,000
	System B		13,900,000
	System C		8,200,000
	System D		15,700,000
	System E		22,100,000
(f)	Land (CRD estimate, 1981)		2,500,000
2.	Operating Costs ($ per year)		
(a)	Labour		
	(i) Boiler plant - assumed to remain constant		633,000
	(ii) RDF plant		
	1980-1995 constant		425,000
	1995 - constant		719,000

(b) Maintenance

(i) Boiler plant - assumed to escalate at 2% per year — $(1.02)^n \times 504,000$

(ii) RDF plant - based on plant throughput and escalates at 2% per year — $(1.046)^n \times 342,400$

(iii) Steam distribution system - covered under labour

(c) Ash and Non-Combustible Disposal

Assume cost of $10 per ton (1981) to deliver and handle at landfill. Volume grows with time (106 tpd in 1984) — $(1.023)^n \times 386,900$

(d) Landfilling of Refuse

Assume cost of $10 per ton (1981) and 6% downtime of plant* — $(1.023)^n \times 102,700$

(e) Insurance and Taxes

Fixed — $ 175,000

(f) Miscellaneous — 100,000

(g) Standby Fuel

Based on 6% boiler downtime* and depends on steam sale. 5% escalation in cost of fuel

(i) Oil

- $1.00 per gal in 1981 or $7.53 per 1000 lb steam
- Q is yearly steam sale in 1000 lb
- cost in 1984 in 1981 $ is $0.06 \times Q \times 8.72 \times (1.05)^n = (1.05)^n \times 0.52\ Q$

*This represents a high degree of reliability. Other figures can be used as needed.

(ii) Gas

- Assumed to be 80% of oil price
- yearly cost = $(1.05)^n \times 0.42\ Q$

3. Repayment of Capital Debt

Assumes a 25-year term with payback in equal yearly installments. Effective payback rate is 15% per year $\frac{0.15 \times \text{capital}}{(1.12)^n}$

4. Income

(a) Ferrous Metals

Value assumed to be $1.00 per ton in 1981 and to increase at 1% per year $(1.033)^n \times 178{,}000$

(b) Electrical Energy

Based on 2% growth in value and power at 13 mills per kWh in 1980 $(1.046)^n\ 887{,}145 - 5.98\ Q(1.02)^n$

(c) Steam

Value is assumed to grow at 5% above inflation. Value, where Q is yearly steam sale in 1000 lb and V is value of steam in $ per 1000 lb is: $(1.05)^n \times V \times Q$

D. Formulae for Expressing Plant Operating Costs

The economic calculations have been arranged so that the net income from operating the cogeneration plant in any year can be established. The income can be negative or positive. The net income represents the cost of disposing of refuse in any one year and the unit cost of disposal can be calculated by dividing the net income by the quantity of refuse delivered in that year.

The basic relation used to calculate net income is:

net income = total revenue - capital redemption charges

- fixed operating costs - variable operating costs

The individual components have been described previously. Various cases can be considered depending on system of steam distribution selected, steam sale and value of steam sold. For System I using natural gas as a standby fuel and as a competitive source of commercial heat, the following relations are obtained. In these the plant is assumed to start operating in 1984, all costs are brought back to 1981 dollars, the power "n" is the number of years after 1984, gas value is assumed to be \$6.34 per million Btu in 1984 and steam is assumed to be worth \$8.21 per 1000 lb in 1984.

Total Revenues

1.	Revenue from ferrous metal	-	$(1.033)^n \times \$178,000$
2.	Revenue from electricity	-	$(1.046)^n \times \$887,145 - 5.98\ Q(1.02)^n$
3.	Revenue from steam	-	$(1.05)^n \times 8.21 \times Q$

Capital Redemption Charges

$$\frac{0.15 \times 41,283,000}{(1.12)^n} = \frac{\$6,192,400}{(1.12)^n}$$

Fixed Operating Costs

1.	Labour	\$1,058,000
2.	Insurance and Taxes	175,000
3.	Miscellaneous	100,000
		\$1,333,000

Variable Operating Costs

1.	Maintenance in Plants	
	- boiler plant	$(1.02)^n \times 504,000$
	- RDF plant	$(1.046)^n \times 342,400$

2. Ash and non-combustible disposal $(1.023)^n \times 67,950$

3. Landfilling refuse $(1.023)^n \times 102,700$

4. Cost of standby gas fuel $(1.05)^n \times 0.42\ Q$

At any time "n" after 1984 the net income is calculated as"

$$\text{Net income} = \left[178,000\ (1.033)^n + 887,145\ (1.046)^n - 5.98\ Q\ (1.02)^n + 8.21\ Q\ (1.05)^n \right] - \left[\frac{6,192,400}{(1.12)^n} + 1,333,000 + 170,000\ (1.023)^n + 504,000\ (1.02)^n + 342,400\ (1.046)^n + 0.42\ Q\ (1.05)^n \right]$$

This equation can be calculated for any year and any set of conditions desired. The principal variables to be examined are:

Q - amount of steam sold per year

n - number of years after start-up

V - value of steam sold, related to fossil fuel being supplanted.

A number of other effects may be examined. For example, as more thermal steam is sold, the amount of electrical energy available from the high pressure steam decreases. The effect on economic calculations is small, but may bear examination after initial sensitivities are investigated.

Initial calculations have been made only to the time when the second boiler and third turbine are added. The procedure for economic calculation after that point follows the same pattern except that additional capital must be written off and extra labour and maintenance are involved. It is obvious that this infusion of extra operating costs does not bring about a corresponding increase in income through sale of electricity and steam.

The net cost of disposal per ton of refuse in any year "n", is"

$$\frac{\text{Net income}}{469(1.023)^n}$$

To obtain the net income and net cost of disposal of refuse in 1981 dollars, the equation may be treated in either of two ways:

1. All costs are entered at 1981 values and are not inflated. Where volume of refuse affects costs, and value of steam and electricity escalates above inflation, the appropriate multipliers are used. The capital replacement term is decreased according to:

$$\text{payment in any year} = \frac{\text{1981 payment}}{(1.12)^n}$$

because the payment is made in inflated dollars. The net income so calculated will be in 1981 dollars.

2. All costs are inflated at the assumed rate (12% per year) and the capital replacement term stays constant at the 1980 value. The net income so calculated is inflated dollars. It can be reduced to 1981 value by any discount factor deemed desirable. Normally, the inflation rate is used.

VI. ECONOMIC EVALUATION OF COGENERATION

A. General

Richard J. Brewer & Associates Ltd. (RJB) has produced a report, "Financial Analysis and Economic Evaluation of the Concept of Cogeneration for the Victoria Metropolitan Area" based on the data of this report. A financial model was developed and used as the basis for evaluating the economics of cogeneration.

RJB's report and the computer program associated with the financial model are included as a separate report with this report.

It will be noted that RJB's data may differ slightly from data presented herein in some cases. The discrepancies are usually small and arise from different interpretation of base data. It is considered that such differences do not materially affect the analysis and the conclusions arising from analysis.

The volume of steam sold does not necessarily reach a maximum in the first year of plant operation. The initial and maximum volumes for the various systems are shown below:

SYSTEM	VOLUME OF STEAM SOLD (LB PER HR)	
	INITIAL	FINAL
I	(16,500)	16,500
II	9,800	9,800
III	(16,500)	20,800
A	16,500	25,000
B	16,500	35,000
C	11,000	16,000
D	27,500	39,100
E	27,500	47,500

The rate at which the maximum will be reached is not known and various assumptions can be made. Since the markets needed to reach the maximum may not develop in initial years of operation, the total capital expenditure for such steam distribution systems as No. A, B, C, D and E need not occur at the time of construction. Although a staged construction of a distribution system would probably occur in practice the financial model assumes that:

- all steam distribution lines for a particular system are installed at the outset:

- steam markets expand at 5% per year from the initial to maximum capacity (applies to Systems A, B, C, D and E only).

Also included in the analysis is one special case which was mentioned briefly under Part I.V.A.5. It was indicated there that B.C. Forest Products Ltd. was not a promising steam market because of the plant's need to dispose of its own wood residues and the company's reluctance to become dependent on an external source of energy. However, to illustrate how a single large steam market could affect economics, a hypothetical cogeneration plant was set up near the B.C. Forest Products Ltd. mill and steam was sold at two different prices to reflect a cost which might appeal to the company.

B. Criteria for Rating Cogeneration Alternatives

The desirability of any alternative may depend on the requirements of the specific receiver rather than on pure economics. Some of the contentious points are:

- The system must reliably dispose of all municipal refuse. This is accepted by all parties.

- The system must dispose of the refuse at as low a cost as possible. Here, disagreement can result from what different viewers perceive to be a low cost because one may consider low capital cost to be important, while another may view long-term income to outweigh initial capital cost.

- The system must be able to accommodate the future amounts of refuse generated in the CRD, and operate at a cost less than the costs incurred by a new landfill or by incineration. Since the present landfilling costs are low it is difficult to envisage the much higher costs which would result from buying a new site and developing to Ministry of the Environment standards.

RJB's report has determined the critical parameters to be considered and these can be identified on the computer printout sheets. These critical parameters are:

1. Unit cost of disposal

   This is the net cost of disposing of one ton of raw refuse and includes all plant costs, ash disposal, waste disposal during plant down periods, and revenue from sale of steam power and scrap metal. This is the price against which any alternative means of disposal will be compared. It may be very high (negative) at the start and becomes positive in later years, providing the plant with a positive cash flow.

2. Net cost of disposal

   This is the net cost of operating the plant in any one year. Typically there is a loss in the first year followed by a gradual decrease in loss with an eventual position of profit. The point at which the net cost of disposal (NR) reaches zero may be looked upon as a break-even point, after which the plant starts to accumulate profits.

3. Cumulative net cost of disposal (CNR)

   The accumulation of all NR's from plant inception leads to an assessment of the ultimate profitability of the operation. At some time hopefully the cumulative net costs become positive, and from that point the plant has recovered early losses and is accumulating profit. The time at which cumulative net costs become zero is always later than the time at which yearly break-even is achieved.

Since the plant is not viewed as an investment, such normal economic measures as return on investment and internal rate of return are not considered.

Thus the criteria of importance are:

- net disposal cost (NPC);
- net revenue or net disposal cost (NR);
- cumulative net revenue or cumulative net cost of disposal (CNR);
- time until NR becomes nil (break-even);
- time until CNR becomes nil;
- capital cost.

C. Rating of the Cogeneration Alternatives

1. Computer Print-Out Sheets

The reader must study the print-out sheets to have a full appreciation of all assumptions and development of costs. In succeeding sections, data are extracted and summarized for easier reading.

2. Net Return and Cumulative Net Return

Table XV summarizes NR and CNR values for all systems other than III (DND) and the B.C. Forest Products special case. It will be observed that Systems I, II and C never reach positive CNR and break-even (nil NR) occurs sometime around the year 2000. Of the remaining systems, D and E are most promising, reaching breakeven about 1993 and acquiring 44 and 54 millions of net revenue by 2008. Interestingly, these are the two most capital intensive projects and might be unattractive because of the large deficits accumulated from 1984 to 1993.

It is an inescapable fact that the plant will lose money in its early years primarily because of:

- high capital write-off costs;

- lower steam sales.

Note that electric energy sales remain nearly constant over long periods, not showing the large growth in value and growth in volume as does thermal energy.

The data show very clearly that volume of steam sold is the most critical parameter and that extra capital can be invested to produce a larger steam market.

Figure 6 shows graphically the net return (NR) with time for various alternatives. Ignoring the BCFP curves for the present, System D or System E show as preferred systems. Of these System E achieves break-even earlier and has a larger ultimate CNR, but System D may be preferable because deficits in early years are lower. It is difficult to view profits 20 years ahead when the plant loses money for 8 to 10 years.

Table XVI summarizes projected economics for the BCFP system assuming steam selling prices of $5.00 and $7.00 per million Btu. Obviously both of these cases are superior because break-even occurs as early as 1990 and losses in early years are small

TABLE XV

SUMMARY OF PROJECTED ECONOMICS

NET RETURN AND (CUMULATIVE NET RETURN)

SYSTEM AND CAPITAL COST	AMOUNT IN GIVEN YEAR ($1,000)									
	1985	1986	1988	1990	1992	1994	1996	2000	2004	2008
I ($41,152,500)	-6,074 (-6,074)	-5,318 (-11,393)	-4,006 (-20,031)	-2,911 (-26,377)	-1,984 (-30,790)	-1,186 (-33,548)	-484 (-34,857)	725 (-33,708)	1,802 (-28,094)	2,858 (-18,253)
II ($37,580,893)	-6,072 (-6,072)	-5,404 (-11,476)	-4,254 (-20,529)	-3,307 (-27,593)	-2,519 (-33,008)	-1,855 (-37,036)	-1,286 (-39,882)	-348 (-42,612)	431 (-42,202)	1,147 (-38,498)
A ($45,029,643)	-6,601 (-6,601)	-5,699 (-12,300)	-4,078 (-21,240)	-2,635 (-27,214)	-1,303 (-30,477)	-175 (-31,310)	692 (-30,350)	2,244 (-23,646)	3,699 (-11,026)	5,190 (7,469)
B ($52,446,786)	-7,889 (-7,889)	-6,871 (-14,761)	-5,058 (-25,750)	-3,468 (-33,457)	-2,024 (-38,213)	-658 (-40,206)	692 (-39,499)	3,578 (-29,645)	5,640 (-9,996)	7,674 (17,594)
C ($45,840,893)	-7,303 (-7,303)	-6,444 (-13,747)	-4,930 (-24,333)	-3,626 (-32,215)	-2,470 (-37,719)	-1,548 (-41,228)	-800 (-43,190)	469 (-43,143)	1,574 (-38,746)	2,637 (-29,526)
D ($54,532,857)	-7,117 (-7,117)	-5,958 (-13,075)	-3,847 (-21,795)	-1,931 (-26,597)	-308 (-27,924)	977 (-26,596)	2,152 (-22,868)	4,297 (-8,838)	6,360 (13,498)	8,534 (44,313)
E ($61,950,000)	-8,466 (-8,466)	-7,196 (-15,662)	-4,902 (-26,576)	-2,848 (-33,275)	-943 (-36,101)	895 (-35,226)	2,704 (-30,764)	5,435 (-12,849)	8,032 (15,362)	10,788 (54,301)

FIGURE 6

NET RETURN FOR VARIOUS SYSTEMS
AS A FUNCTION OF TIME

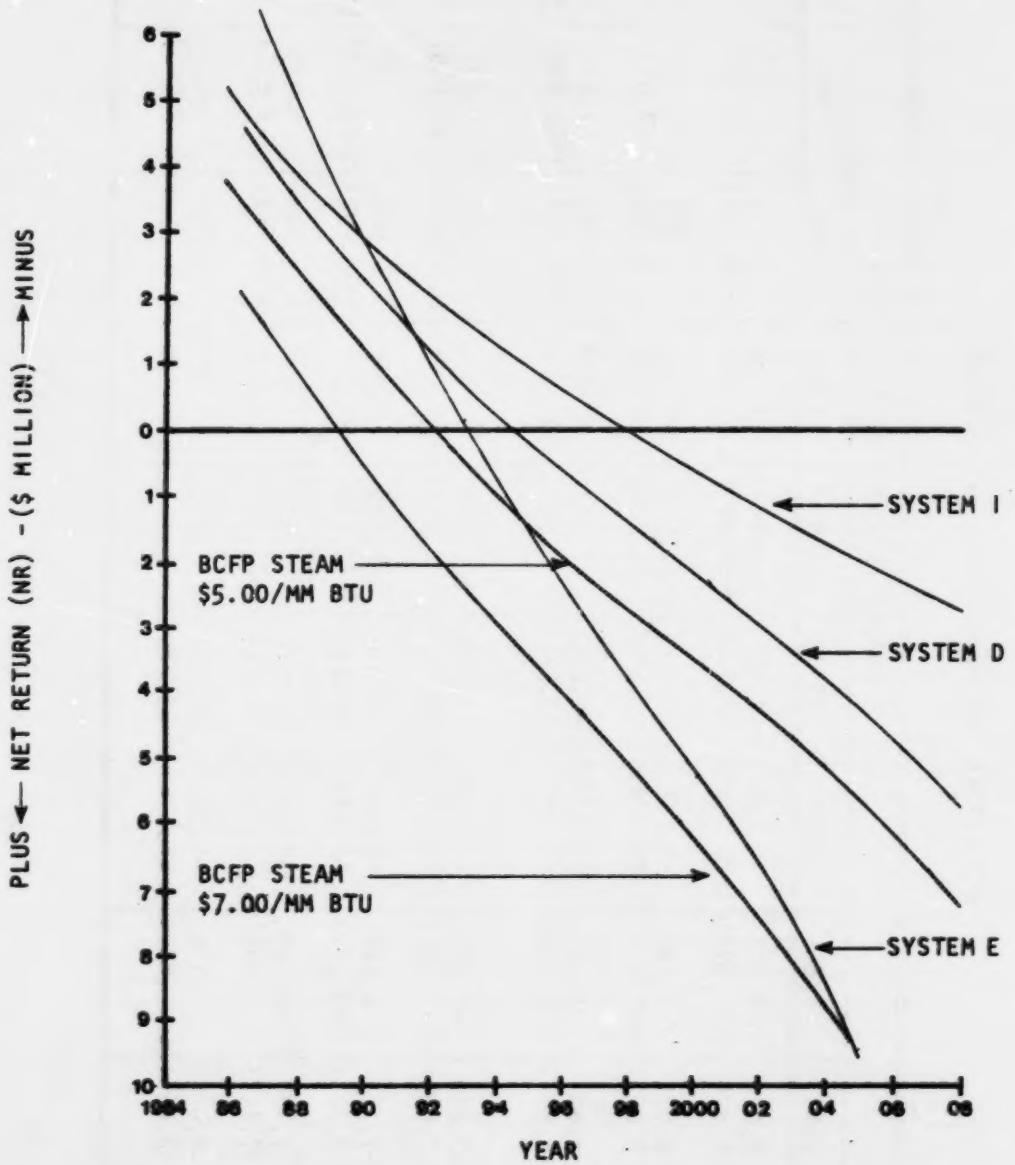


TABLE XVI

SUMMARY OF PROJECTED ECONOMICS

B.C. FOREST PRODUCTS CASE ONLY

	AMOUNT IN GIVEN YEAR ($1,000)									
	1985	1986	1988	1990	1992	1994	1996	2000	2004	2008
Steam at $5.00/MMB ($38,097,143)										
Net Return	-4,372	-3,562	-2,110	-837	303	1,349	2,331	4,193	6,044	8,052
Cumulative Net Return	-4,372	-7,934	-12,854	-15,145	-15,094	-12,909	-8,732	5,273	26,654	55,778
Steam at $7.00/MMB ($38,097,143)										
Net Return	-3,117	-2,230	-614	839	2,175	3,435	4,650	7,041	9,512	12,267
Cumulative Net Return	-3,117	-5,347	-7,359	-6,391	-2,696	3,552	12,249	36,826	71,115	115,933

relative to those projected for the other systems. Note that for all other systems steam was assumed to be worth $9.00 per million Btu, so that a large initial steam market can offset much lower prices which must be accepted to obtain the market. Unfortunately, this favoured market, for the present at least, is hypothetical.

3. Net Cost of Refuse Disposal (NPC)

In all calculations no credit has been assigned for what might be a reasonable landfilling cost. Therefore, the disposal costs shown should be compared with what future disposal costs might be, not with the costs of disposal at the Hartland Road Landfill which is terminal at present filling rate. If the co-generation plant is installed, the existing fill will suffice for the foreseeable future.

Figure 7 shows disposal costs ($ per ton) for three systems as a function of time. The exciting prospect of a profit from plant operation occurs somewhere around 1993 for a favoured and feasible system. Note that one of the BCFP systems is not markedly superior in this presentation to System D even though the capital cost of D is much greater and the volume of steam sold is less. Of course, the BCFP system with $9.00 steam would be very attractive, but $5.00 might be a reasonable price that could be obtained from a forest industry plant.

4. Sensitivity Analysis

(a) To Price of Steam

Figure 8 shows the sensitivity of disposal cost and net cumulative revenue to the initial sales price of steam. In 1985 the net disposal cost is not sharply dependent on steam value, chiefly because at this time steam sales will be relatively small and capital redemption charges are at a maximum. In 2009 the dependence is marked reflecting low capital redemption costs and increased volume and escalated value of steam (5% per year).

The CNR increases sharply as steam value increases, going from a slightly negative value at $6.00 to 48 million dollars at $12.00 steam.

Figure 9 shows the relation between break-even point and initial price of steam. For System D an increase in steam price from $6.00 to $12.00 per million Btu advances the break-even point by six years. The CNR (deficit) with the same charge is reduced from 40 million dollars to 20 million dollars.

FIGURE 7.

NET COST OF REFUSE DISPOSAL AT COGENERATION PLANT

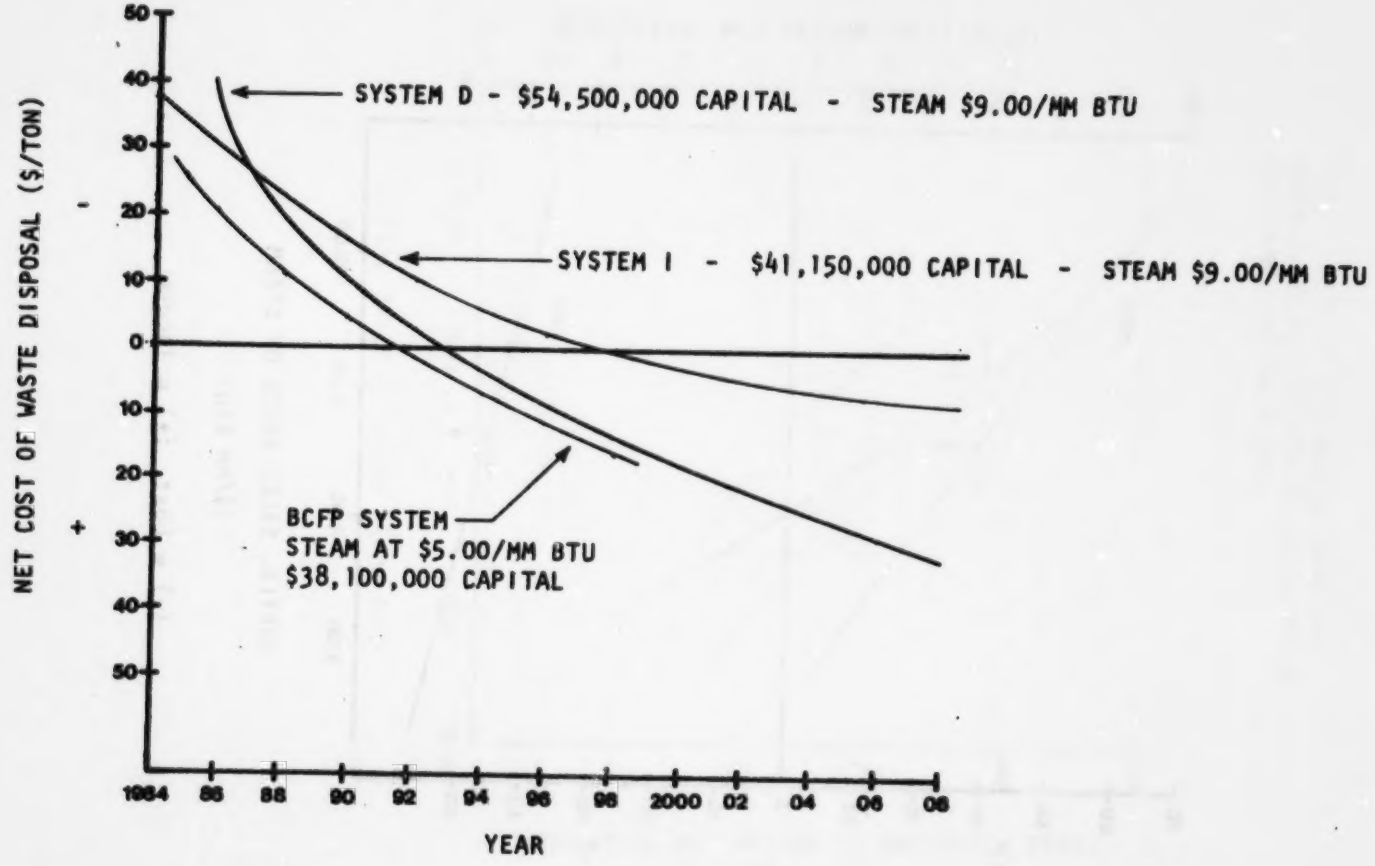


FIGURE 8. SENSITIVITY OF DISPOSAL COST AND CUMULATIVE NET RETURN TO INITIAL SALES PRICE OF STEAM, SYSTEM D.

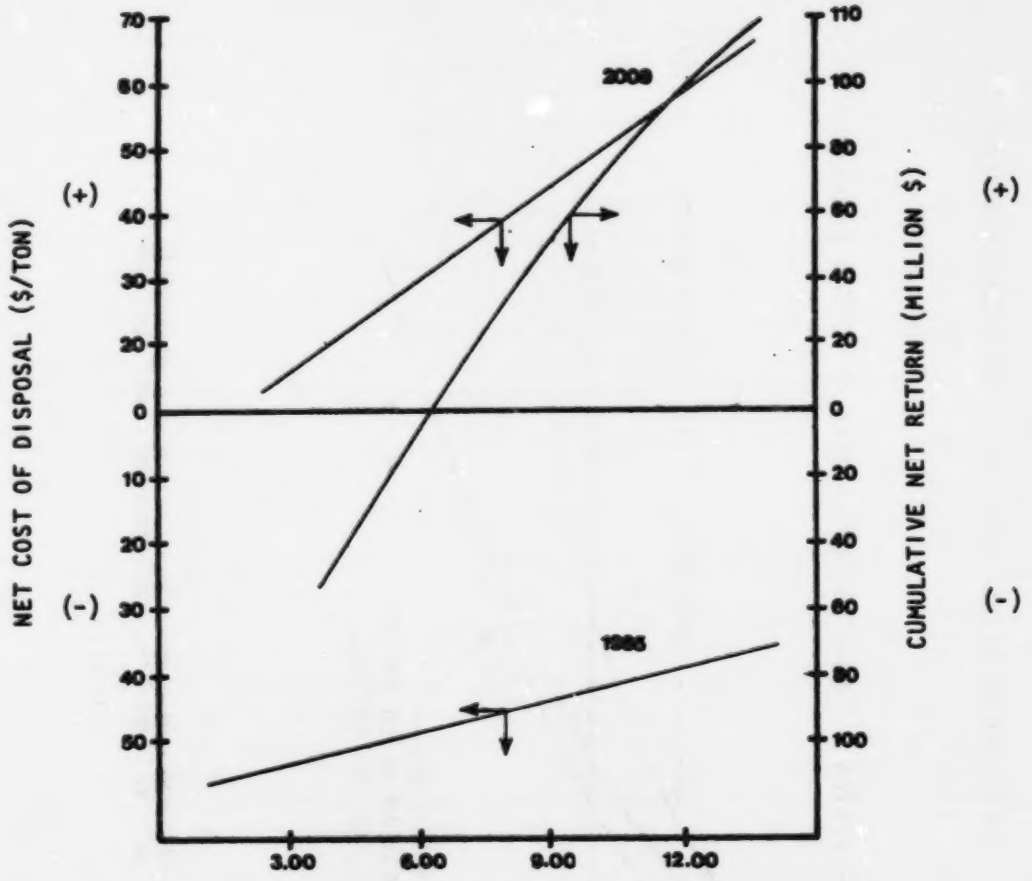
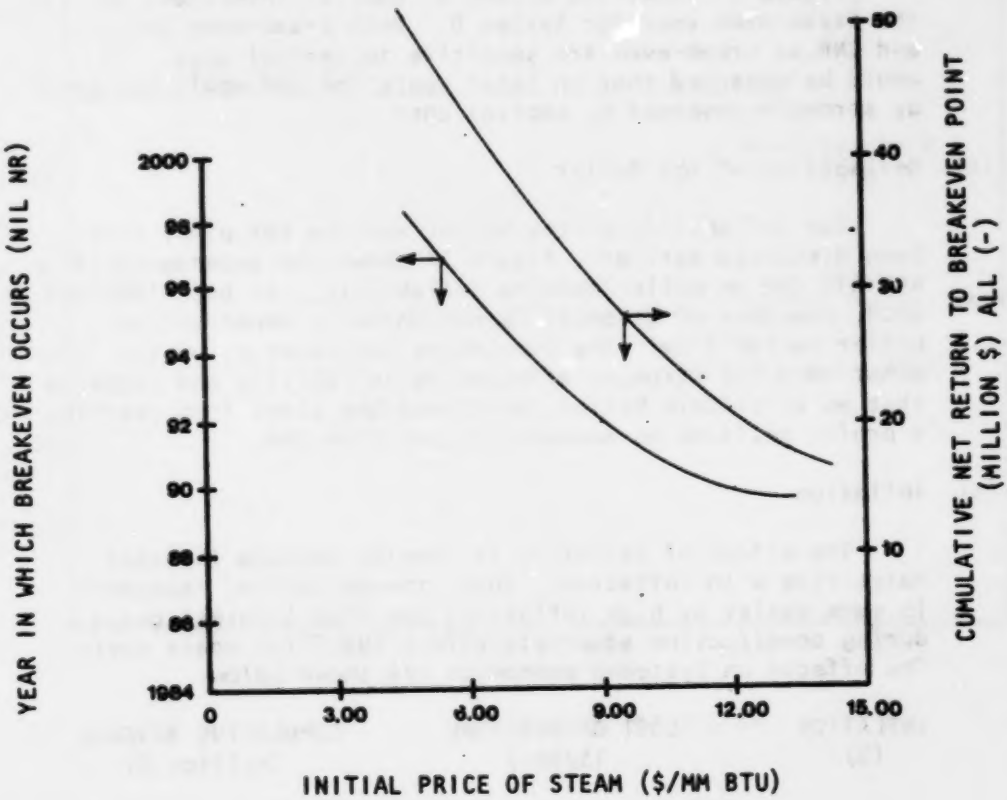


FIGURE 9

SENSITIVITY OF BREAKEVEN POINT AND CUMULATIVE NET RETURN TO SALES PRICE OF STEAM, SYSTEM D ONLY



(b) To Capital Cost to the CRD

Figure 10 shows the relation between net cost of disposal of refuse (NPC) and capital cost. Costs less than the estimated base value are considered to result from government grants, while higher values result from cost overruns. In 1985 (first year) the cost of disposal is sensitive to capital cost. In 2009 capital cost has very little effect on disposal cost.

Figure 11 shows the effect of capital investment on the break-even year for System D. Both break-even point and CNR at break-even are sensitive to capital cost. It would be expected that in later years the CNR would not be as strongly governed by capital cost.

(c) Reliability of the Boiler

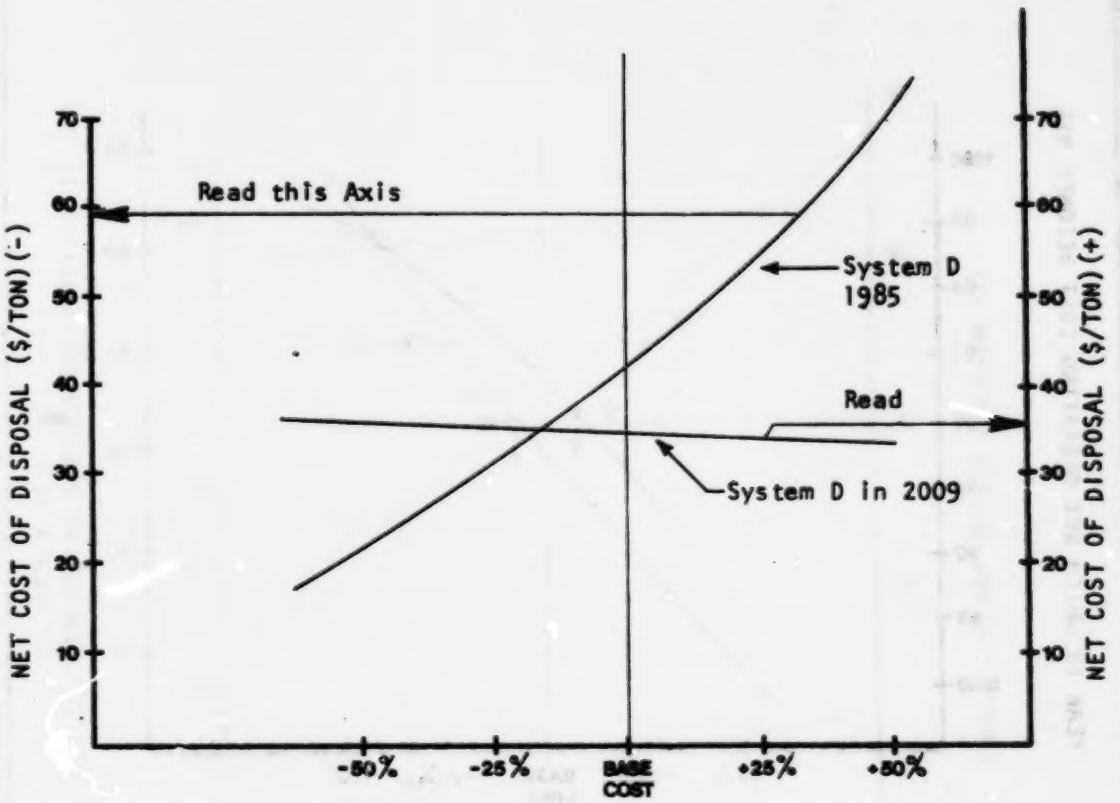
The reliability of the boiler and the RDF plant have been discussed earlier. Figure 12 shows the dependence of NPC and CNR on boiler/turbine reliability. In both 1985 and 2009, the cost of disposal is not markedly dependent on boiler reliability. The cumulative net revenue, on the other hand, is strongly affected by reliability and suggests that an unreliable boiler could keep the plant from reaching a profit position as measured by positive CNR.

(d) Inflation

The effect of inflation is complex because interest rates rise with inflation. Thus, though capital repayment is made easier by high inflation, the high interest costs during construction adversely affect the first years costs. The effects on System D economics are shown below.

INFLATION (%)	COST OF DISPOSAL ($/ton)		CUMULATIVE REVENUE (million $)	
	1985	2009	1992	2009
8	-29	+33	-19.3	+52.5
12	-44	+34	-29.6	+46.6
16	-61	+35	-39.0	+41.6

FIGURE 10. SENSITIVITY OF DISPOSAL COST TO CAPITAL COST TO THE CRD



BASE COST SYSTEM D = $54,532,857

+25% IS A CAPITAL CONTINGENCY OF 25%

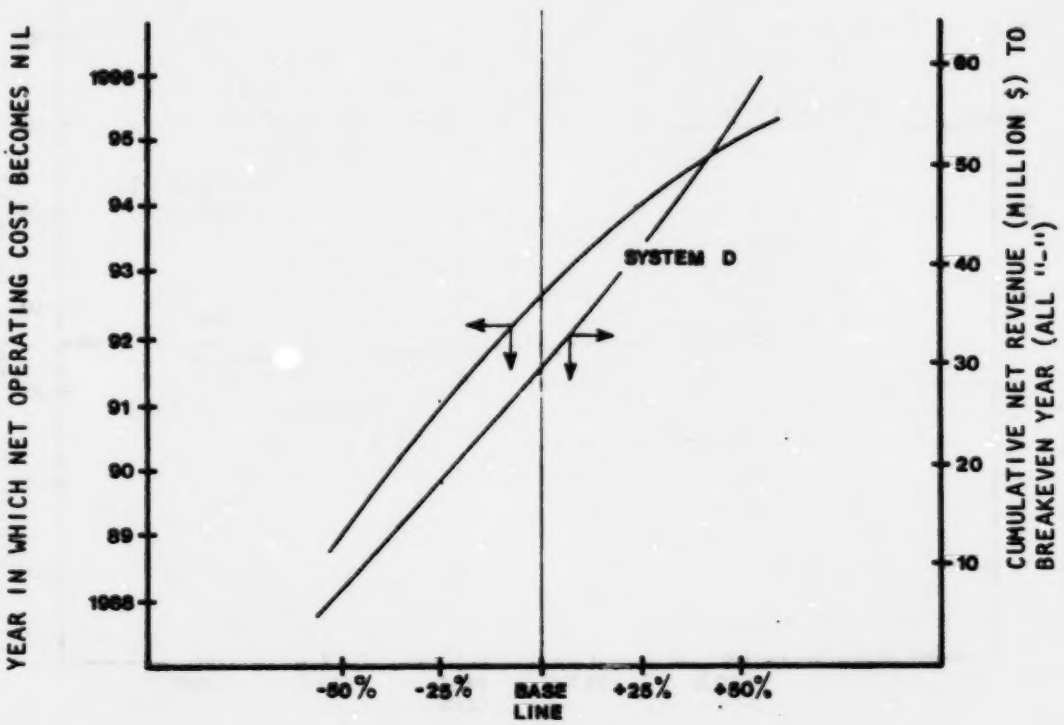
-25% REPRESENTS A GRANT OF 25%

(-) REPRESENTS A COST

(+) REPRESENTS INCOME

FIGURE 11

SENSITIVITY OF BREAK-EVEN POINT
TO CAPITAL INVESTMENT BY CRD



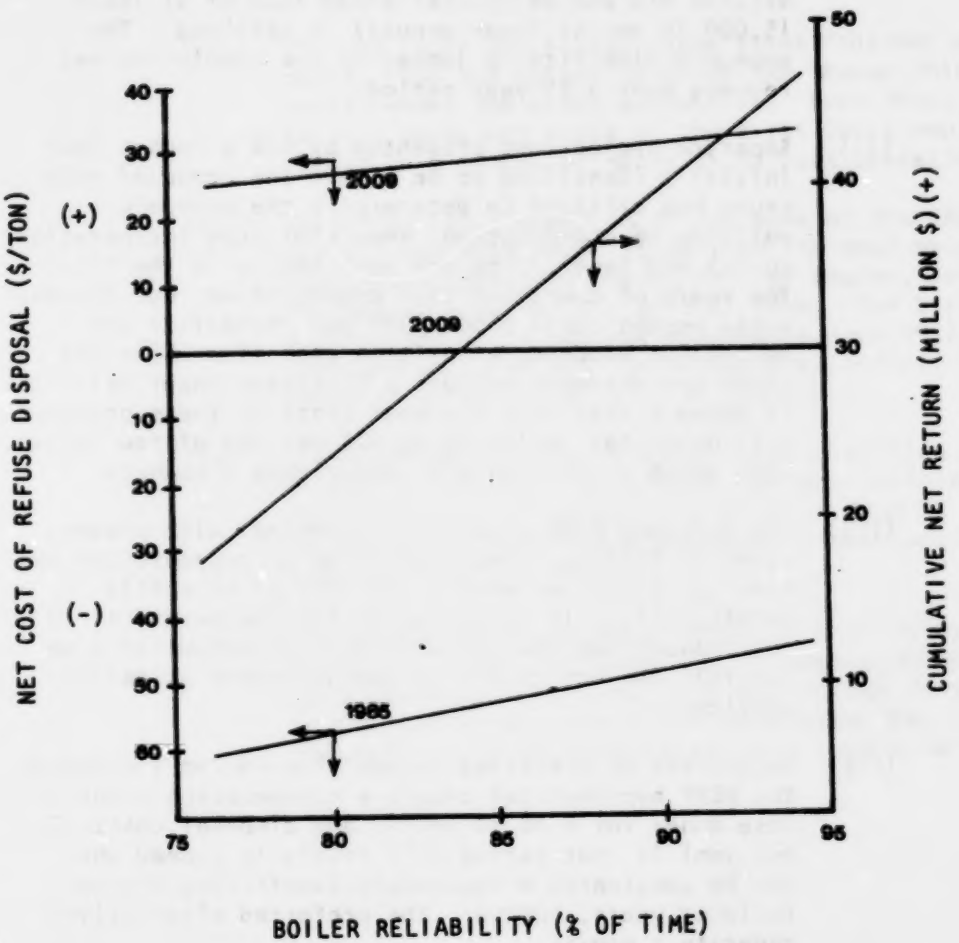
BASE COST SYSTEM D = $54,532,857

+25% IS A CAPITAL CONTINGENCY OF 25%

-25% REPRESENTS A GRANT OF 25%

FIGURE 12

SENSITIVITY OF DISPOSAL COST AND CUMULATIVE NET REVENUE TO RELIABILITY OF RDF BOILER, SYSTEM D



(e) Findings of Economic Evaluation

It is difficult to present findings without restricting them by qualifications. However, certain facts do emerge clearly.

(i) Disposal of domestic refuse by combustion, leading to generation of steam and electricity, is economically viable if steam in 1984 can be sold for $9.00 per million Btu and an initial steam load of at least 15,000 lb per hr (mean annual) is obtained. The economic viability is judged by the cumulative net revenue over a 25-year period.

(ii) Separate projections presented by RJB's report (not initially identified to be within the scope of this study but critical in determining the economic validity of cogeneration) show that pure incineration (bulk) and landfilling are less costly in the first few years of operation than cogeneration, but disposal costs become equal about 1990 and thereafter cogeneration produces a positive cash flow while the other two disposal methods will always incur deficits. It appears that unit disposal costs by these processes will never fall below about $15 per ton of raw refuse. This value is in line with experience elsewhere.

(iii) The Hartland Road Landfill is terminal with present rates of filling. Implementation of cogeneration by burning refuse can extend the life of this fill indefinitely. If cogeneration (or incineration) is not implemented the CRD will have to establish a new landfill subject to all of the stringent guidelines applicable.

(iv) Regardless of preferred system alternative (including the BCFP hypothetical case), a cogeneration plant will lose money for 6 to 10 years, and disposal costs ($ per ton) in that period will initially exceed what may be considered a reasonable landfilling charge. In later years, however, the preferred alternatives generate a profit.

(v) The preferred systems (D and E) in 25 years are projected to accumulate up to $50 million dollars of profit, but by the time annual break-even operation is

achieved, these systems will have accumulated deficits of $25 million and $35 million respectively. Thus, if the cogeneration plant is to be constructed some method of handling this deficit operating period has to be developed.

(vi) In all cases, quantity of steam sold is of paramount importance, even though capitalization has to be increased to achieve the larger market.

(vii) The CRD lacks one single large steam consumer which could, from the outset, provide the income which would render the plant attractive. Even then, capital repayment costs in the first years would result in a number of years of deficit operation.

(viii) The effect of a grant to offset some of the CRD's capital expenditure is to advance the year at which break-even operation occurs and, of course, to reduce the accumulated deficit at that time. For System D, a 25% grant would advance break-even from 1992 to 1990 and would reduce the accumulated deficit from $29 million to $18 million at that point.

(ix) Plant reliability is critical in establishing whether or not a preferred system ever becomes profitable. For System D, for example, a decrease from 94 to 77% reliability results in a decrease in cumulative net revenue of $25 million.

(x) The Study has developed a method of evaluating technical and economic feasibility of cogeneration based on combustion of refuse. The methodology developed is applicable to other situations where the feasibility of refuse disposal must be evaluated.

VII. RECOMMENDATIONS

1. In view of the limited alternatives available to the CRD for continuing disposal of its refuse, it should proceed immediately with implementation of System D. Note that if the CRD does not proceed with cogeneration, a decision still has to be made on the future of refuse disposal, and the alternatives almost certainly will be more costly than cogeneration.

2. Implement System D (or any comparable scheme) in the following phases:

   (a) Confirm the steam sales by interviews with the building owners involved.

   (b) Re-examine cost/value of steam in light of the proposed natural gas pipeline and the probable cost of natural gas on Vancouver Island.

   (c) Establish more closely the form of contract B.C. Hydro would be prepared to enter into.

   (d) Establish a means of alleviating the early operating deficit which makes cogeneration politically and psychologically unattractive:

      (i) Possibility of using a government grant to offset operating deficits rather than for reducing capital.

      (ii) A modified tax on CRD residents and businesses as suggested by RJB.

   (e) Start plant design and expedite construction.

3. Continue discussions with BCFP to assess any arrangements which could be made with them for steam use. The changing conditions of the forest industry must be considered in any such discussions.

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3. "Energy Recovery from Solid Waste, Capital Regional District", June 1, 1976, B.H. Levelton & Associates Ltd.

4. "Solid Waste Conversion to Energy Alternatives for Cooperative Effort Between Capital Regional District and Department of National Defence", B.H. Levelton & Associates Ltd., April 4, 1978.

5. "Municipal Solid Waste Recovery at Canadian Forces Bases and Stations", L.F. Cade and T.G. Barton, Civil Eng. Research Report No. CE77-2, Royal Military College, May 1977.

A. DESIGN PARAMETERS

1. Power Plant Size

Size of the Energy Complex was determined by the estimated projected refuse quantity available. Phase I of the study based the future amount of RFD quantity on an assumed population growth. Several alternative growth patterns were considered. The most likely one is based on a 2.3% increment above a linear population growth each year. This assumption was considered for the purposes of sizing the power plant in this phase of the study. It is assumed that in the year of 1979, a quantity of 209 ton per day of mean average bone dry refused derived fuel (RDF) was available and this amount will increase yearly by a factor of 2.3% for the lifetime of the plant. See Table A Column 2.

The 209T/D represents the mean average RFD quantity available in the year of 1979. Sizing of the plant was based on the following assumption:

Plant Size = Mean Average Capacity + 20% for peaks + 10% for contingencies

or specifically in the year 1979

$$209 \times 1.2 \times 1.1 = 275 \text{ T/D}$$

See Table A Column 2.

It is necessary to design the plant for 20% peaks as the waste quantity collected in times is consistently more than that of the yearly mean average and therefore its incineration cannot be taken care by the installation of adequate storage capacity.

2. Power Plant Steam Conditions

For the type of boiler that must be considered for this particular application, the pressure limitation is about 1500 psig. Because of the potential for corrosion, the final steam temperature on refuse fired boilers should be held as low as possible and not exceed 750°F. For this steam temperature application a two stage superheater, using an interstage spray attamperator for final steam temperature control, is utilized to reduce tube metal alloy requirement.

As steam is produced for power generation, a low boiler operating pressure and temperature is not feasible. A condition of 600 psig/750°F has been adopted for the study for testing the economic feasibility of the project. A higher cycle efficiency resulting from a higher throttle steam pressure will marginally increase the electrical power output but the resulting increase in output and revenue must be compared with the higher capital cost incurred by such a system.

3. Feed Water Heating

In most power plant cycles, feed water heating is employed as a means of improving overall cycle efficiency.

A certain amount of feedwater heating is provided at the deaerator. This can be supplemented by extracting steam at other pressure stages of the steam turbine. This extraction steam can be used to increase the temperature of the boiler feed water in closed type feed water heaters.

The drop in electrical power generation resulting from the reduction in steam flow through the low pressure stages of the turbine is usually more than compensated for by the improvement in efficiency of the power cycle.

However, due to the preliminary nature of this study, the feasibility of adding more turbine extraction points and feedheaters to improve overall plant heat rate has not been considered.

4. Sale of Steam

Phase I of the study has discussed and listed the potential markets for the sale of steam. It was concluded that it is highly probable that the full utilization of the cogenerated steam for sale could not be considered at the present time. Equipment selected for the power plant was therefore considered only for the partial production of saleable steam at 40 psig pressure produced through turbine extraction.

Thus a single extraction condensing turbine was selected for the plant. Table A Column 7 shows that the assumed 50,000 lb/hr of steam sold in 1984 could double to 100,000 lb/hr by the end of the plant life time assumed to be 30 years for the waste cogenerating complex.

5. Plant Availability-Operating Hours

Let the availability of a boiler and its auxiliaries be B(A) and the availability of a turbine and its auxiliaries be T(A). For the type of boiler and turbine under consideration in this study the following availabilities have been assumed.

B(A) = 0.77 - Boiler and associated auxiliaries
T(A) = 0.98 - Turbine generator and associated auxiliaries

Thus for our power plant comprising one boiler and two turbine generators the plant availability is:

$B(A) \times T(A)^2 = 0.77 \times 0.98^2 = 0.74$

or 74% of its operating time.

Considering a planned annual shut down period of 21 days, the number of operating days per year would then come to:

$$0.74 \times (365 - 21) = 255 \text{ days}$$

And the number of days when the plant is not in operation would be:

Planned outage days = 21

Forced outage days = $(1 - 0.74)(365 - 21) = 89$

or a total of 110 days per year corresponding to a plant availability of 70 per cent.

6. Potential Electricity Production

Having established the amount of RFD available in the first year of the plant operation - assumed to be in 1984 - Table A was prepared showing the size and production figures for the 30 year life time of the Cogenerating Complex.

This table shows that the amount of fuel and consequently, the plant size will double by the year 2014. The amount of potential produced electricity as shown will increase from 7000 kW to almost 14,000 kW while selling steam, or 9,750 kW to 19,200 kW when all steam is utilized in producing power with none for sale.

7. Heat Balances

Heat balances were prepared for the following four cases:

Case No.	Year	Plant Size(T/D)	Steam Sold(lb/hr)	Power Generated(
1	1984	300	50,000	7,000
2	1984	300	nil	9,750
3	2014	600	100,000	13,970
4	2014	600	nil	19,200

All heat balances were based on the following common design criterias:

Boiler Pressure	600 psig
Boiler Temperature	750°F
Boiler Efficiency	70%
Turbine Size (each)	7000 kW
Turbine Type	Single extraction - condensing
Turbine Efficiency	
Condensing	70%
Extraction	65%
Generator Efficiency	95%
Air Cooled Condenser	
Pressure	3" Hg abs.
RDF Calorific value	6500 BTU/lb

Table A shows production quantities that would be produced by the plant at its installed capacity. Actual yearly average output of the plant would be approximately 75% of these figures.

Heat balances 1 to 4 are included at the end of Section A.

8. STANDBY STEAM GENERATOR

A packaged boiler has been included to operate during periods of plant shut down (110 days per year) supplying steam to turbines for generating power and steam for sale.

The amount of bunker "C" fuel oil required is calculated as follows:

Fuel Oil = 0.3 x (Column 3 Table A) x 77 x 0.75 (USG/day)

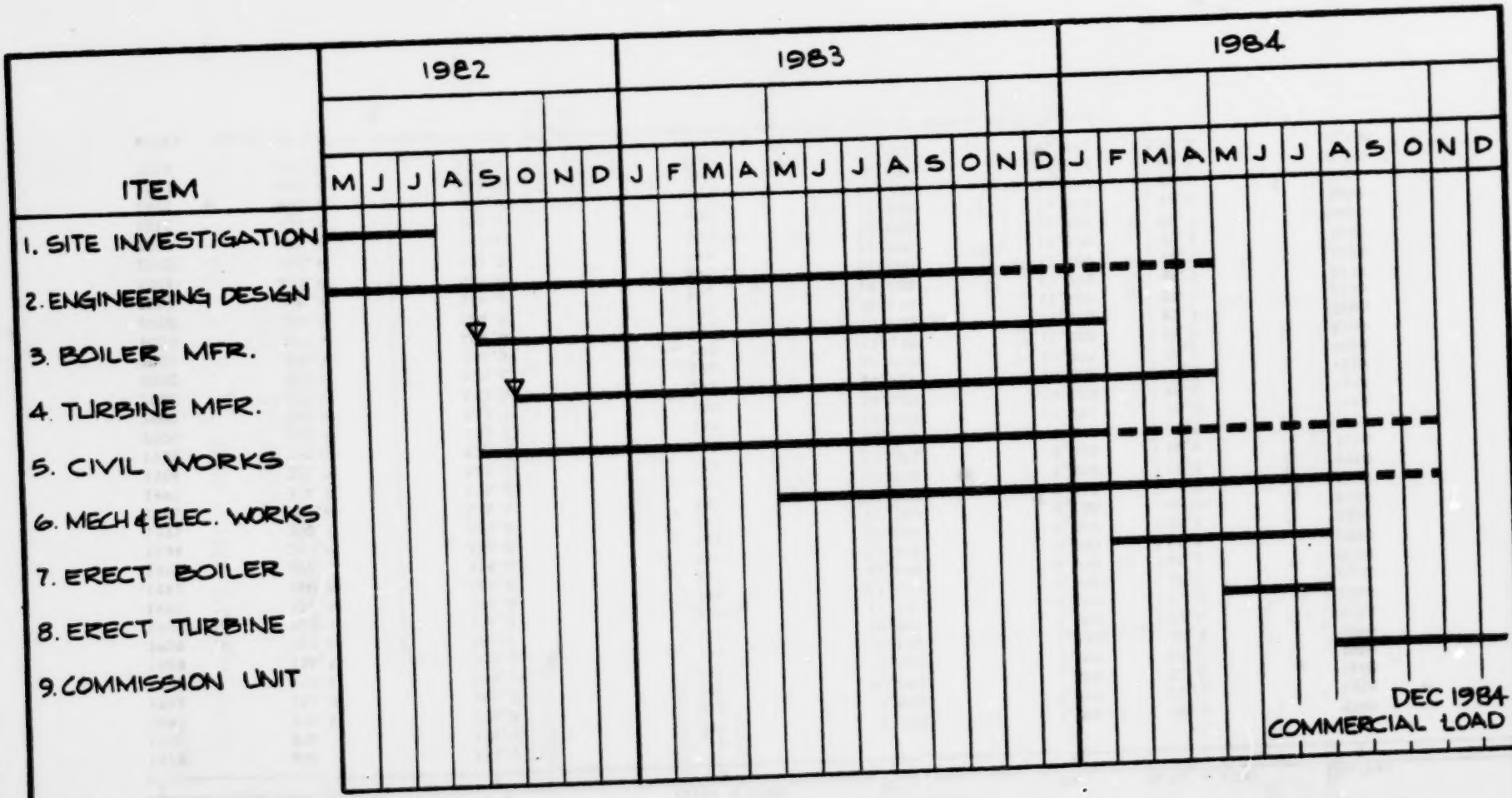
where:

0.3	means 110 days per year
Col. 3 Table 6	max RDF production (T/D)
77	USG of oil per Ton of RDF (see Appendix IV)
0.75	load factor

Column 8, Table A includes the fuel oil requirement of the plant for its planned lifetime.

9. PROJECT SCHEDULE

The attached schedule highlights the duration of significant events only. It has been assumed that the site investigation commence in May 1983, with full commercial load being achieved by year end of 1984.


ITEM
1982
1983
1984
M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D
1. SITE INVESTIGATION
2. ENGINEERING DESIGN
3. BOILER MFR.
4. TURBINE MFR.
5. CIVIL WORKS
6. MECH & ELEC. WORKS
7. ERECT BOILER
8. ERECT TURBINE
9. COMMISSION UNIT
DEC 1984
COMMERCIAL LOAD
▽ DATE OF ORDER

CAPITAL REGIONAL DISTRICT
VICTORIA B.C.
COGENERATION STUDY
REFUSE DERIVED FUEL (RDF) - 400 T/D PROJECT SCHEDULE

TABLE A - COMPOSITE TABLE

YEAR	DISPOSABLE RPD MEAN AVE. T/D	PLANT SIZE RDF MAX. WITH 10% CONT. T/D	BOILER PLANT SIZED STEAM GENERATED lb/hr x 1000	POWER GEN. ONLY @100% LF POWER GEN. NO STEAM SOLD KW	POWER GEN. & STEAM SOLD @100% LF POWER GEN. KW	STEAM SOLD lb/hr x 1000	BUNKER 'C' OIL REQUIRED FUEL OIL USG/Day
1	2	3	4	5	6	7	8
1979	209	275.0	-	-	-	-	
1984	234	300.0	112	9,750	7,000	50.0	5200
1985	239.5	308.0	114	9,950	7,240	51.3	5370
1986	245.0	316.0	117	10,180	7,400	52.6	5440
1987	250.7	324.0	119	10,410	7,500	53.6	5560
1988	256.5	333.0	125	10,650	7,750	56.3	5690
1989	262.4	342.0	128	10,900	7,900	57.6	5830
1990	268.3	351.0	131	11,150	8,100	59.0	5960
1991	274.5	360.0	134	11,400	8,300	60.3	6100
1992	280.8	369.0	137	11,660	8,500	61.6	6230
1993	297.3	378.0	140	11,940	8,680	63.0	6380
1994	294.0	386.0	143	12,200	8,880	64.4	6520
1995	300.7	395.0	147	12,500	9,100	66.0	6680
1996	307.6	404.0	150	12,770	9,300	67.5	6830
1997	314.7	414.0	153	13,070	9,500	68.9	6990
1998	322.0	423.0	157	13,370	9,730	70.6	7150
1999	329.0	433.0	161	13,680	9,970	72.5	7310
2000	336.9	443.0	165	14,000	10,200	74.3	7480
2001	344.6	453.0	168	14,300	10,400	75.6	7650
2002	352.6	463.0	172	14,650	10,600	77.4	7830
2003	360.7	474.0	176	15,000	10,900	79.2	8010
2004	369.0	484.0	179	15,330	11,100	81.0	8200
2005	377.5	494.0	183	15,700	11,400	83.3	8380
2006	386.2	504.0	187	16,050	11,600	85.0	8570
2007	395.0	514.0	191	16,400	11,900	86.8	8770
2008	404.0	525.0	195	16,800	12,200	88.7	8970
2009	413.4	536.0	199	17,200	12,500	90.9	9200
2010	422.9	548.0	203	17,600	12,800	93.2	9400
2011	432.6	560.0	206	17,900	13,000	94.9	9600
2012	442.6	573.0	210	18,400	13,380	96.6	9800
2013	452.8	586.0	215	18,800	13,670	98.3	10,000
2014	461.0	600.0	220	19,200	13,970	100.0	10,280

NOTES: Amount of RDF is assumed to grow in geometric progressive parallel to a birthrate of 2.3%/year.

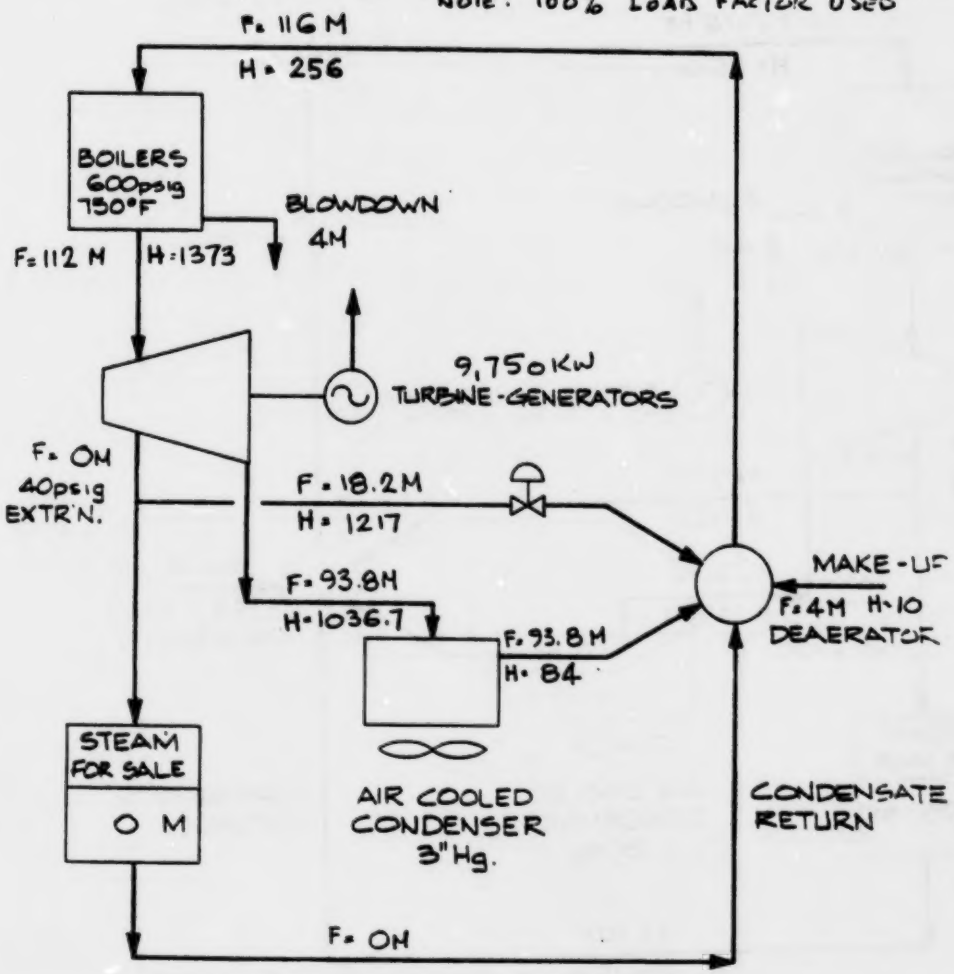
LEGEND

- H = BTU/lb
- F = lb/hr
- T = °F

POWER GENERATED:

CONDENSER	= 93.8/10.5 =	8,930
40 psig EXTRACTION	= 18.2/22.3 =	820
	TOTAL	9,750

NOTE: 100% LOAD FACTOR USED



CAPITAL REGIONAL DISTRICT

HEAT BALANCE

NOMINAL CAPACITY 300 T/D RDF - NO STEAM SOLD

(YEAR 1984)

CASE I

LEGEND

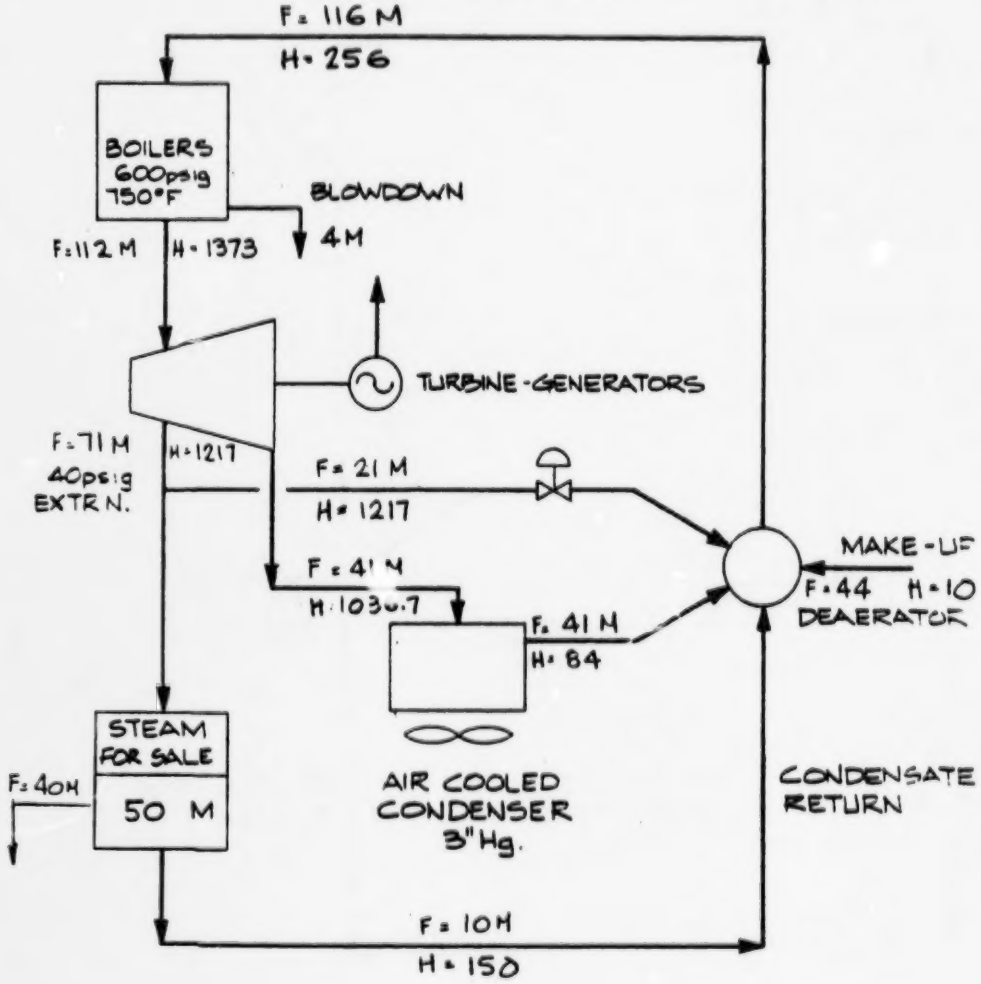
H = BTU/lb

F = lb/hr

T = °F

POWER GENERATED:		
CONDENSER	= 41/10.5	= 3.90
40 psig EXTRACTION	= 71/22.3	= 3.10
	TOTAL	7.00

NOTE: 100% LOAD FACTOR USED



CAPITAL REGIONAL DISTRICT

HEAT BALANCE

NOMINAL CAPACITY 300 T/D RDF - STEAM SOLD

(YEAR 1984)

CASE II

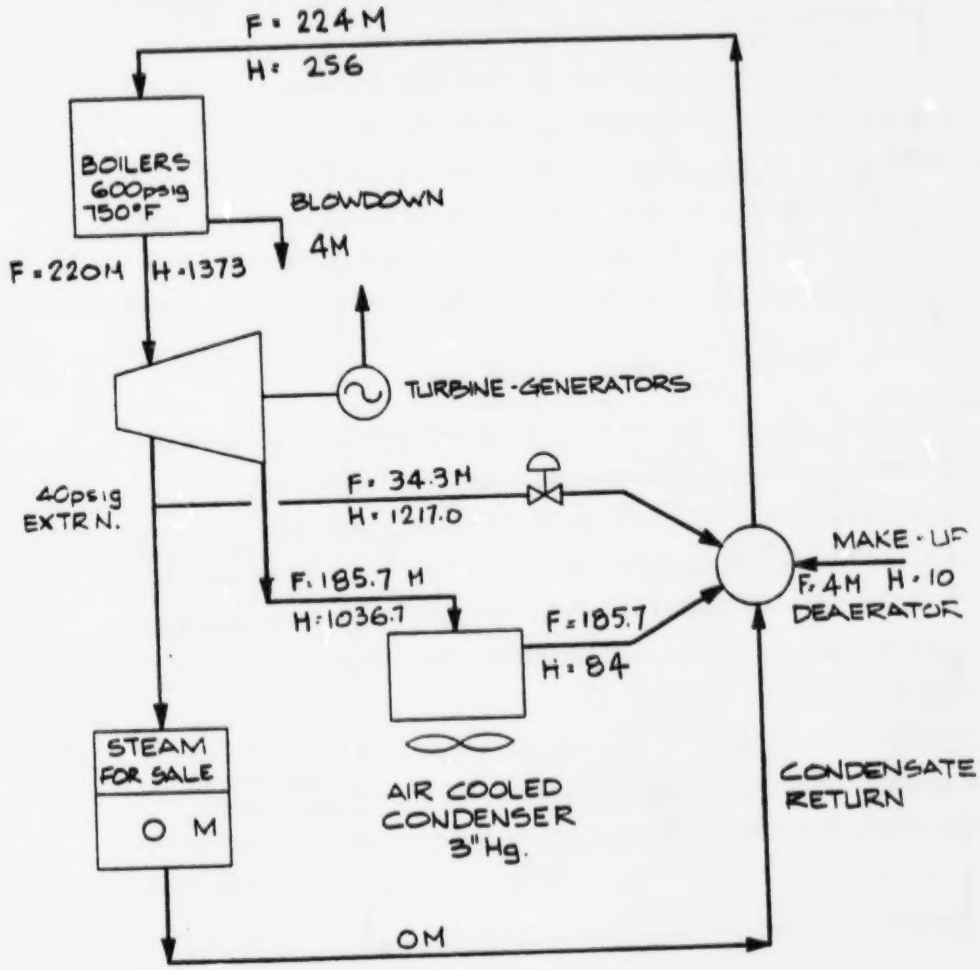
- LEGEND

- H = BTU/lb
- F = lb/hr
- T = °F

POWER GENERATED:

CONDENSER	= 185.7/10.5 =	17.680
40 psig EXTRACTION	= 34.3/22.3 =	1 540
	TOTAL	19,220

NOTE: 100% LOAD FACTOR USED



CAPITAL REGIONAL DISTRICT

HEAT BALANCE

NOMINAL CAPACITY: 600 T/D RDF – NO STEAM SOLD

(YEAR 2014)

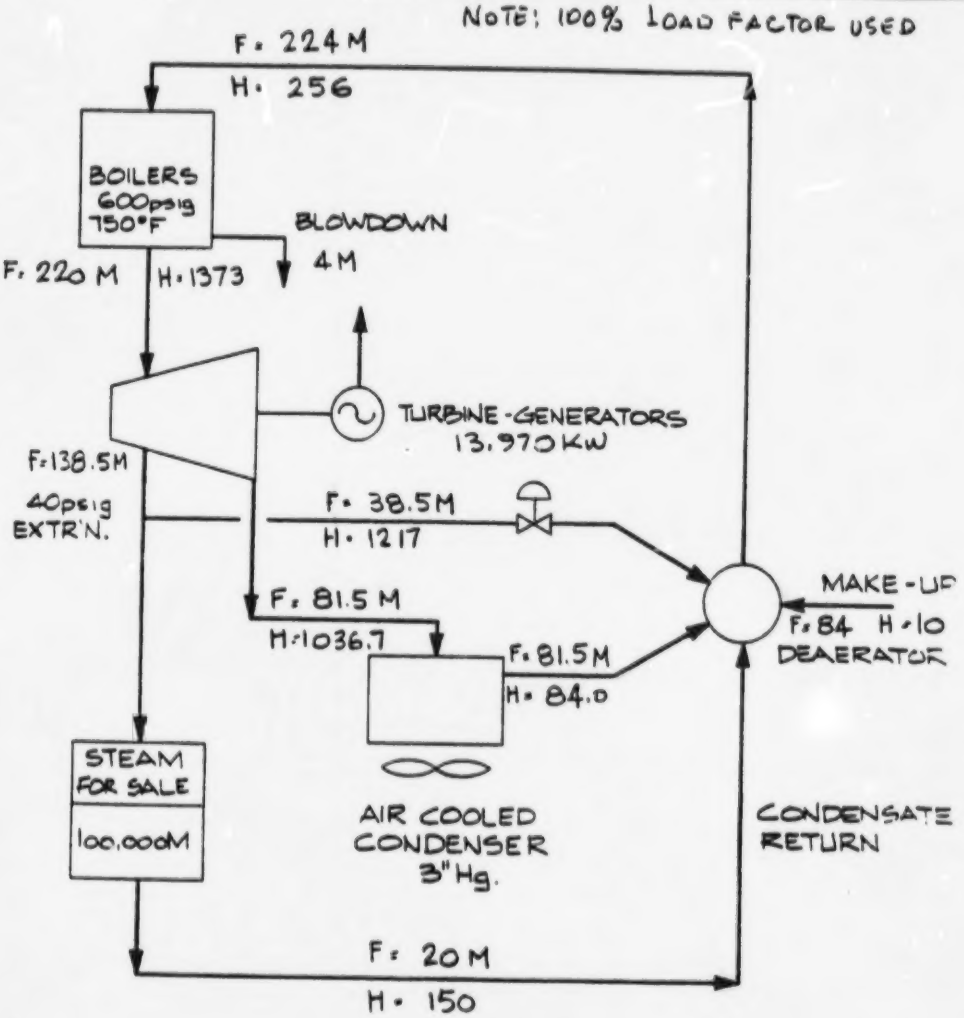
CASE III

LEGEND
- H = BTU/lb
- F = lb/hr
- T = °F

POWER GENERATED:

CONDENSER	= 81.5/10.5	= 7,760
40 psig EXTRACTION	=	= 6,210
	TOTAL	13,970

NOTE: 100% LOAD FACTOR USED



CAPITAL REGIONAL DISTRICT

HEAT BALANCE

NOMINAL CAPACITY 600 T/D RDF - STEAM SOLD
(YEAR 2014)

CASE IV

B. POWER PLANT DESCRIPTION

1. GENERAL

This Section describes in general the operation of the RDF Cogenerating power plant amd its components.

The Energy Complex has most of the features of a conventional coal fired utility electric power plant. Fuel is prepared for firing in a boiler which generates steam for delivery to a conventional condensing steam turbine generator. The major technical difference is in the boiler design which requires the application of special combustion techniques to successfully burn refused derived fuel (R.D.F).

The description and design data outlined in the following, refers to the first phase of the Congenerating Complex, a 400 ton per day incinerating plant comprising of one 400 T/D boiler, two (2) 7,000 kW, turbine-generators and required auxiliaries as shown in solid line on drawings D-0148-510-440 entitled COGENERATION - REFUSE DERIVED FUEL (RDF) - PLANS AND SECTIONS included in Appendix II.

Phase II to be installed by 1996 will comprise the addition of a 200 T/D boiler and a third turbine C/W auxiliaries all planned to be added in 1996 to handle the projected waste quantities until the year 2014 for a total of a 30 years planned lifetime of the complex.

2. POWER PLANT (400 T/D installed in Phase I)

Refused derived fuel would be transported by air from the fuel preparation plant to a storage bin in the power plant.

The storage would hold a capacity of approximately 8 hours of boiler supply fuel at design output. This storage capacity would help to even out fuel supply during load fluctuation.

The storage bin would be self unloading, with live bottom and would discharge into variable speed screw conveyor. The speed of the conveyor could be controlled by the boiler demand.

The screw conveyor would discharge into a vibrating conveyor which would spread and distribute the waste to the boiler feed chutes.

Refused derived fuel would be fired in the steam generator with a rated steaming capacity of 150,000 lbs/hour at 600 psig and 750°F. Fuel oil would be used during startups and as necessary to stabilize combustion. Steam from the boiler would be discharged to two single extraction condensing steam turbines with a nominal rating of 7,000 kW each. Steam supply for sale (if applicable) and for the deaerating feedwater heater would be extracted from the turbines at 40 psig. The balance of the steam would pass through the low pressure section of the turbines and would exhaust to the air cooled condenser operating at 3 inches of mercury absolute.

The air cooled condenser would condense the steam and the condensate would then be returned to the deaerator.

Continuous blowdown from the steam generator steam drum would discharge to a flash tank operating at 40 psig. Steam from the tank would flash to the deaerator and the condensate would discharge to the blowdown tank.

A demineralizer plant would provide make-up water to the system at the deaerator. Level control valves in the make-up water line would control the water level in the deaerator storage tank.

The deaerator would operate at 40 psig. Pressure would be maintained by a pressure control valve in the turbine extraction steam system. Feed pumps would supply boiler water from the deaerator storage tank.

Internal chemical feed systems would be provided. Phosphate would be added to the boiler drum, sulphite to the deaerator and a filming amine to steam piping to combat corrosion of the piping system.

During periods of power plant outage power generation and low pressure steam supply for sale would be maintained by a packaged boiler supplying 40 psig saturated steam to the low pressure steam distribution system.

The power plant comprises the following major components and systems:

2.1 Steam Generator
2.2 Electrostatic Precipitator
2.3 Turbine Generators
2.4 Air Cooled Condenser
2.5 Condensate and Feed Water Systems
2.6 Chemical Feed System
2.7 Water Treatment System
2.8 Compressed Air System
2.9 Ash Handling System
2.10 Boiler Blowdown System
2.11 Auxiliary Steam System

The following describes briefly each system:

2.1 Steam Generator

Initially there would be one steam generator installed with a steam raising capability of 150,000 lbs/hr at 600 psig/750°F.

The steam generator would be of the two-drum stirling type Boiler design and would be fired by refused derived fuel and No. 6 fuel oil.

Steam generators incorporating refuse incineration are subject to considerations in addition to those normally related to high temperature operation. Some of these considerations are:

1. Fireside corrosion of boiler tubes
2. Correct choice of furnace fire resistant lining
3. Effect of incineration on boiler stack discharge (pollution control requirements)

Oil firing equipment would be provided for start-up and combustion stabilization purposes. The steam generator would be a natural circulation type, including water cooled furnace, boiler section and superheater tube banks. The field erected unit would be complete with forced and induced draft fans and a high pressure overfire air blower.

A combustion air heater of the vertical tubular type would be provided. A steam coil air heater would preheat air prior to entering the tubular air heater to prevent cold end corrosion at partial load operation.

The boiler unit would also include soot blowers with control panels and associated pipe work, air and flue gas ducting, wind swept spouts and oil fired auxiliary burners, thermal insulation, structural steel supports, permanent access stairways, ladders and walkways, and all piping, valves, fittings, instrument inserts and connections.

2.2 Electrostatic Precipitator

An electrostatic precipitator would be included at the back of the boiler with an efficiency of 99.3% by weight resulting in an outlet particle loading of 0.1 grains per standard cubic feet. It would include the flange to flange precipitator, complete with support and access steel, screw conveyors and rotary valves for connection to the ash handling system and it would be complete with insulation and cladding.

2.3 Turbine Generators

Two steam turbine-generators of the single automatic-extraction condensing type would be included with a nominal rating of 7,000 kW each.

The units would be designed for a steam inlet throttle condition of 600 psig/750°F, with 40 psig extraction, exhausting to the air cooled condenser at 3 inches mercury absolute.

The steam turbines would be of the radial flow design directly coupled to the generator and would be supplied complete with steam strainer, combined trip and throttle valve, speed governor, automatic extraction regulator, automatic non-return valve, gland seal system, insulation and removable sheet metal jacket.

The generators would be of the enclosed, self-ventilating air-cooled type and would be supplied complete with air cooling system, temperature detectors, static excitation and lubrication system.

2.4 Air Cooled Condenser

The condenser would be of the direct air cooled type to overcome the lack of available cooling water and to help eliminate water and air pollution.

The condenser would be located on the roof of the turbine building and would utilize fans to circulate air around the coils containing the steam. The condensate would then be returned to the deaerator for reuse in the feed water cycle. The condenser would be designed for the total steam capacity of the plant.

2.5 Condensate and Feed Water Systems

Condensate extraction pumps would be installed to transfer the condensate from the Condenser to the Condensate tank. One unit would normally be in operation with the second as standby. The pumps would be motor driven.

A portion of the low pressure steam sold is assumed to be returned to the power plant as condensate. An ample size condensate receiver would be provided.

Condensate would then be pumped through polishing units before being returned to the deaerator. Motor driven condensate transfer pumps would be installed.

Two trains of demineralizers would be provided, for make-up water treatment. Each train would be supplied complete with resin bed, piping, valves, fittings, and regeneration system.

Three boiler feed pumps would be provided. Two of the units would be motor driven. The third unit would have a dual steam turbine-electric motor drive.

One deaerator-feed water heater would be installed, having a design capacity of 250,000 lbs/hr. Steam to the deaerator would be supplied at 40 psig. The deaerator would be of the tray type and would be provided with a 10 minutes feed water storage capacity tank. The deaerator would be supplied complete with vent condenser, relief valve, vacuum breaker, vent valve, and all associated accessories.

2.6 Chemical Feed System

Chemical feed systems would be provided for the boiler water, deaerator and the steam piping system.

Complete package units would consist of chemical dissolving and storage tank, feed pump and motor drive, agitator (if required), relief valve, interconnecting piping and valves. The pumps would be of the positive displacement type with adjustable stroke. Each chemical feed tank would be of stainless steel or plastic construction.

2.7 Water Treatment System

A water treatment plant would be provided to supply make-up water to the boiler. This plant would comprise two 100 percent demineralizer trains.

Each demineralizer train would consist of one cation and one anion exchange unit complete with exchange material, all necessary interconnecting piping and valves, and a regeneration system.

A treated water storage tank would be supplied with a capacity of one hour's storage at normal design rating. Two 100% treated water transfer pumps would be provided to feed the treated water to the deaerator.

2.8 Compressed Air System

Two air compressor units would be provided, each having a capacity of 200 scfm of oil free air at 100 psig. The units would be complete with motor drive, inter-cooler, after-cooler, and all associated auxiliaries. An air receiver and dryer would be part of the system.

Instrument air and service air would be supplied from the same system. The system would be arranged in such a way that a loss of pressure in the instrument air system will curtail flow to the service air system and thus protect the instrument air system supply.

2.9 Ash Handling System

The boiler would be equipped with an ash handling system of the air operated type including necessary hoppers with clinker grinder, grates, ash silo and all inter connecting special piping and valves.

2.10 Boiler Blowdown System

The boiler would be equipped with a continuous blowdown heat recovery system. The system would consist of a flash tank which would take blowdown from the steam drum and flash the steam down to the 40 psig system.

The flash tank would be provided with a relief valve, gauge, glass high water level alarm and a float-operated drain valve located in the tank outlet in order to maintain constant liquid level in the flash tank.

2.11 Auxiliary Steam System

An auxiliary steam system would be included in order to maintain the sale of steam and power for sale during forced or planned power plant outages.

The system would comprise of one packaged boiler of 220,000 lbs/hr capacity operating at 600 psig/750°F. The boiler would include a burner system, instrumentation and controls. The main boiler feed pumps would supply feed water to the auxiliary boiler.

The auxiliary steam supply would be connected to the turbine-generators and the 40 psig low pressure steam system. The boiler would be equipped with its own stack.

C. CAPITAL COST

1 Capital Cost

The following tables compiled to supply capital cost estimate for the RDF fired cogenerating complex. The capital cost of the plant is broken down to the following two sections;

1. Capital Cost of a 400 T/D plant (to be installed in 1984).
2. Capital Cost of the addition of one(1) 200 T/D boiler, one(1) 7000 kW steam turbine and auxiliaries (to be installed in 1996).

Capital costs are based on rough engineering designs and include only the power plant part of the Complex. No allowance has been made for the cost of land or material handling and preparation plant. Major equipments were sized and prices were obtained from suppliers. Most subsystems such as piping, wiring and labour for installation were estimated.

All costs have been given in 1980 dollars. In general contingency, engineering, administration, contractors overhead and interest during construction has not been allowed for.

TABLE C

DETAILED

CAPITAL COST ESTIMATE

A - MECHANICAL EQUIPMENT & INSTRUMENTATION

(To be installed in 1984)

Item Number	Description	Capital Cost (1980 Dollars)
1.	One 400 ton/day RDF fired steam generator with I.D., F.D. Fan and high pressure air blower, all auxiliaries and supporting steelwork (erected)	$4,000.000
2.	One electrostatic precipitator	420.000
3.	Instrument and controls	400.000
4.	Two (2) 7,000 kW steam turbine-generator complete with all auxiliaries (erected)	3,900.000
5.	Breeching and ductwork	130.000
6.	Ash handling system (erected)	650.000
7.	Three motor driven boiler feed pumps	100.000
8.	Condensate transfer pumps	40.000
9.	Miscellaneous pumps	25.000
10.	Air cooled steam condensers	1,400.000
11.	Storage bin	400.000
12.	Deaerator and associated equipment	40.000
13.	Condensate polishing plant	30.000
14.	Demineralizer plant	100.000
15.	Air compressors, air dryer and accessories	40.000

Item Number	Description	Capital Cost (1980 Dollars)
16.	One 220.000 lb/hr package boiler and auxiliaries	1,760.000
17.	Piping and valves	500.000
18.	Insulation and lagging	420.000
19.	Miscellaneous tanks	45.000
20.	Heating and ventilation	15.000
21.	Cranes and hoists	25.000
22.	SUB TOTAL	14,440.000
23.	Installation and erection	2,200.000
	TOTAL	$16,640.000

B - ELECTRICAL EQUIPMENT

Item Number	Description	Capital Cost (1980 Dollars)
1.	Transformers	$ 260.000
2.	Circuit breakers	240.000
3.	Motor control centres	60.000
4.	Cables	120.000
5.	Lighting	20.000
6.	DC equipment	12.000
7.	Control boards	38.000
	SUB TOTAL	$ 750.000
8.	Installation and erection (labour)	1,000.000
	TOTAL	$1,750.000

C - STRUCTURAL AND CIVIL

Item Number	Description	Capital Cost (1980 Dollars)
1.	Materials	$1,000.000
2.	Labour	600.000
	TOTAL	$1,600.000

D - TOTAL CAPITAL COST ESTIMATE

Materials and Labour (excluding contingency, engineering and administration, contractors overhead and profits, and interest during construction)	$19,990.000

COST OF THE ADDITION OF A 200 T/D BOILER & AUXILIARIES

(To be installed in 1996)

Item Number	Description	Capital Cost (1980 Dollars)
1.	One 200 T/D RDF fired steam generator complete with I.D., F.D. fans and high pressure air blowers, all auxiliaries and supporting steel work (erected)	$3,000.000
2.	One (1) 7000 KW steam turbine generator C/W all auxiliaries	1,950.000
3.	Breeching and ductwork	70.000
4.	Ash handling	80.000
5.	Air cooled steam condenser	700.000
6.	Piping and valves	150.000
7.	Insulation and lagging	40.000
8.	Storage bin	300.000
9.	Electrical equipment	100.000
	SUB TOTAL	$6.390.000
10.	Installation and erection (labour)	730.000
	TOTAL	$7,120.000

D. OPERATING COST

The following operating costs have been considered:

Maintenance

Maintenance including material and labor has been estimated at $450,000 per year (in 1980).

Administration and Insurance

The administration and general costs including insurance of operating the complex have been calculated on the basis of 39% of the operating maintenance cost in accordance with accepted practice.

Operating Labour

The annual cost of operating staff has been based on the following staff requirements for operation of the power plant on a three shift-per-day basis:

TABLE 1: STAFF REQUIREMENTS FOR THE POWER PLANT*

STAFF DESCRIPTION	NO. OF STAFF	SALARY/YEAR
Superintendent	1	$ 37.000
1st Class Operators	6	$168.000
3rd Class Operators	6	$126.000
Labourers	3	$ 45.000
Maintenance	2	$ 42.000
		$419.000 (in 1980)*

* Does not include Material Handling Operators

Heavy Fuel Oil

Quantities are given in Table A Column 8 in Appendix I.

Ash Disposal

Based on 12% ash content or 0.12 ton/T of RDF cost could be calculated by the following formula by assuming 10 dollars per ton of ash disposal charge

Ash Disposal Cost = 0.12 x 10 x T/D dollars (in 1980)

where T/D is Table A Column 2.

The following is a summary of operating cost considered:

TABLE 2: OPERATING COST (1980)

1.	Maintenance	$450,000/year
2.	Admin. & Insurance 0.39 x 450,000	$175,000/year
3.	Operating Labour	$419,000/year
4.	Fuel Oil	From Table A Column 8.
5.	Ash Disposal	$ 1.20/T

NOTES

Item 1. Estimates

2. Use 39% of Maintenance

3. See Table 1 STAFF REQUIREMENTS FOR THE POWER PLANT

APPENDIX I

TABLE A - COMPOSITE TABLE

YEAR	DISPOSABLE RFD MEAN AVE. T/D	PLANT SIZE RDF MAX. WITH 10% CONT. T/D	BOILER PLANT SIZED STEAM GENERATED lb/hr x 1000	POWER GEN. ONLY @100% LF NO STEAM SOLD KW	POWER GEN. & STEAM SOLD @100% LF POWER GEN. KW	STEAM SOLD lb/hr x 1000	BUNKER 'C' OIL REQUIRED FUEL OIL USG/Day
1	2	3	4	5	6	7	8
1979	209	275.0	-	-	-	-	
1984	234	300.0	112	9,750	7,000	50.0	5200
1985	239.5	308.0	114	9,950	7,240	51.3	5370
1986	245.0	316.0	117	10,180	7,400	52.6	5440
1987	250.7	324.0	119	10,410	7,500	53.6	5560
1988	256.5	333.0	125	10,650	7,750	56.3	5690
1989	262.4	342.0	128	10,900	7,900	57.6	5830
1990	268.3	351.0	131	11,150	8,100	59.0	5960
1991	274.5	360.0	134	11,400	8,300	60.3	6100
1992	280.8	369.0	137	11,660	8,500	61.6	6230
1993	287.3	378.0	140	11,940	8,680	63.0	6380
1994	294.0	386.0	143	12,200	8,880	64.4	6520
1995	300.7	395.0	147	12,500	9,100	66.0	6680
1996	307.6	404.0	150	12,770	9,300	67.5	6830
1997	314.7	414.0	153	13,070	9,500	68.9	6990
1998	322.0	423.0	157	13,370	9,730	70.6	7150
1999	329.0	433.0	161	13,680	9,970	72.5	7310
2000	336.9	443.0	165	14,000	10,200	74.3	7480
2001	344.6	453.0	168	14,300	10,400	75.6	7650
2002	352.6	463.0	172	14,650	10,600	77.4	7830
2003	360.7	474.0	176	15,000	10,900	79.2	8010
2004	369.0	484.0	179	15,330	11,100	81.0	8200
2005	377.5	494.0	183	15,700	11,400	83.3	8380
2006	386.2	504.0	187	16,050	11,600	85.0	8570
2007	395.0	514.0	191	16,400	11,900	86.8	8770
2008	404.0	525.0	195	16,800	12,200	88.7	8970
2009	413.4	536.0	199	17,200	12,500	90.9	9200
2010	422.9	548.0	203	17,600	12,800	93.2	9400
2011	432.6	560.0	206	17,900	13,000	94.9	9600
2012	442.6	573.0	210	18,400	13,380	96.6	9800
2013	452.8	586.0	215	18,800	13,670	98.3	10,000
2014	461.0	600.0	220	19,200	13,970	100.0	10,280

NOTES: Amount of RDF is assumed to grow in geometric progressive parallel to a birthrate of 2.3%/year.

APPENDIX II

APPENDIX III

POWER PLANT (Power Requirement)

MOTOR LIST

SERVICE	HP	RPM
Boiler Feedwater Pump #1	200	3600
Boiler Feedwater Pump #2	200	3600
Boiler Feedwater Pump #3	200	3600
F.D. Fan RDF Boiler	200	1800
I.D. Fan RDF Boiler	400	1800
O.A. Blower RDF Boiler	200	1200
Stoker RDF Boiler	10	1200
F.D. Fan Packaged Boiler	60	1800
Condensate Pump #1	20	3600
Condensate Pump #2	20	3600
Hot Well Extraction Pump #1	20	3600
Hot Well Extraction Pump #2	20	3600
Desuperheating Pump #1	10	3600
Desuperheating Pump #2	10	3600
Chemical Injection Pumps 4 x ½	4	
Compressor #1	100	1800
Compressor #2	100	1800
Sootblower 10 x ½	5	1200
Ash Sluicing Pump #1	200	1800
Ash Sluicing Pump #2	200	1800
Oil P & H Set Pump #1	20	1800
Oil P & H Set Pump #2	20	1800
Water Treatment Regeneration Pump #1	20	1800
Water Treatment Regeneration Pump #2	20	3600
Ventilation Fan #1	40	1800
Ventilation Fan #2	40	1800

SERVICE	HP	RPM
Turbine Room Supply Fan	30	1800
Roof Exhaust Fan #1	15	1800
Roof Exhaust Fan #2	15	1800
Crane Bridge	10	1200
Crane Hoist	20	1600
Aux Lube Oil Pump	5	1800
Aux Governing Pump	5	1800
Precipitator	220 KW	
TOTAL NAME PLATE =	1900 HP	

R.D.F. PREPARATION PLANT

TOTAL NAME PLATE: 2100 HP (by Levelton)

Assume 75% load factor

TOTAL PLANT OPERATING POWER = (1900 + 2100) x 0.75 = 3000 HP

$$\text{ratio } \frac{\text{Power Used}}{\text{Power Output}} = \frac{3000}{21.000 \times 1.34} = 10.7\% \text{ of generating capacity}$$

APPENDIX IV

CASE I **ELECTRICITY GENERATED**

$$\frac{19,200}{600} \times 0.75 \times 24 = 576 \text{ kW/T}$$

CASE II **ELECTRICITY AND STEAM GENERATED**

Electricity $\frac{13,960}{600} \times 0.75 \times 24 = 419 \text{ kW/T}$

Plus

Steam $\frac{100.000 \times 24}{600} \times 0.75 = 3000 \text{ lbs/T}$

FUEL OIL REQUIRED

RDF Plant does not operate 110 days/year.

STEAM GENERATED per T of RDF

$$\frac{220.000}{600} \times 24 = 8800 \frac{\text{lb of steam}}{\text{T of RDF}}$$

FUEL OIL REQUIRED

Heat

$$\text{BTU/T} = \frac{8800 \times (1373-256)}{0.85} = 11.55 \times 10^6 \text{ BTU/T}$$

Oil

$$= \frac{11.55 \times 10^6}{0.15 \times 10^6} = 77.0 \text{ USG/T}$$

ASH DISPOSAL

Assume 12% ash content or 0.12 Ton of ash per T RDF

assume $10/T of ash disposal charge

Cost of ash disposal

0.12 x 10 = $1.20/T RDF

INTERIM REPORT

ANALYSIS OF MARKET FOR STEAM HEATING IN THE CAPITAL REGIONAL DISTRICT

PREPARED BY:

D.W. THOMSON CONSULTANTS LTD.
534 Broughton Street
Victoria, British Columbia
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MAY 8, 1980

File Ref. 80-5991-V

INTERIM REPORT

MAY 8, 1980

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INTERIM REPORT

MAY 8, 1980

ANALYSIS OF MARKET FOR STEAM HEATING IN THE CAPITAL REGIONAL DISTRICT

PREPARED BY: D. W. THOMSON CONSULTANTS LTD.

TERMS OF REFERENCE

To carry out at survey of buildings of any significant size in the district to determine:

a) whether their heating systems could be converted to make use of a steam service.

b) their present annual energy consumption.

c) their peak requirement -

d) their minimum requirement.

SURVEY METHOD

Building owners or building managers were approached and everyone contacted was fully cooperative. The managers of larger buildings and government agencies had more detailed information and could often provide not only annual consumption figures, but monthly breakdowns and peak figures.

Even when monthly and peak figures are not available it is possible to arrive at figures by using degree day analysis, (Appendix 1) and B.C. Hydro load charts, (Appendix 2). Where full records were available they could be checked against this method. In general it was found that the following is fairly consistent:

	January	July
Hotels	14% of annual total	4% of annual total
Offices	16% of annual total	2% of annual total

SURVEY METHOD (continued)

Exceptions to this are Labatts Brewery which has a constant production requirement and Victoria General Hospital which operates a laundry and has a 6.4% July figure.

Some discretion was used in selecting the buildings. Relatively small buildings in the downtown core were included while similar size buildings further out were not. This was because it is obviously impractical to extend a steam distribution system to small isolated locations.

Some large buildings are listed with zero figures because they have electric systems without a central source which could use steam. These are listed for the sake of completeness. Many electrically heated apartments in peripheral areas have not been listed.

The majority of the buildings listed are heated with light oil as the fuel.

We did not contact the following possible markets because they were being approached by B.H. Levelton & Associates.

Canadian Forest Products
DND Esquimalt
City asphalt plant

DISCUSSION WITH CITY OF VICTORIA

An informal discussion with Mr. C. Goldie, the underground services engineer for the City, focused on the difficulty of running an underground steam main through the core areas. He provided a copy of his report prepared in 1968, (Appendix 3) when another system was being considered. This is nct their official response but it does give some overall idea as to what their concerns may be. The congestion of services at street intersections has increased since 1968 due to the extensive installation of underground electrical and telephone services.

DISCUSSION WITH B. C. B. C.

It was mentioned that some consideration is being given to burning peletized wood waste in the Parliament Buildings steam plant. The boilers were originally solid fuel fired and so it is thought that a conversion to wood waste may be feasible.

POTENTIAL MARKET ANALYSIS - CITY OF VICTORIA

	BUILDING	ANNUAL BTU X 10^6	JULY BTU X 10^6	JANUARY BTU X 10^6	PEAK HOUR BTU X 10^3/HR.
	Provincial Government				
1.	Parliament Buildings	59500	2020	8400	23400
2.	Dogwood Building	2320	50	350	1000
3.	Wadington Building	8120	160	1200	3350
4.	Law Courts	5800	120	870	2420
5.	Richard Blanshard	8700	180	1300	3600
6.	St. Anne's Academy	5220	105	780	2170
7.	780 Blanshard	1740	35	260	725
8.	Rithet Building	1740	35	260	725
	City of Victoria				
9.	Crystal Pool	14060	560	1970	5470
10.	Arena	2810	50	420	1170
11.	Centennial Square	6190	125	930	2580
12.	Royal Theatre	2610	50	390	1080
	Hotels				
13.	Empress Hotel	40820	2450	5710	15850
14.	Chateau Victoria	11600	460	1620	4500
15.	Executive House	4200	160	590	1650
16.	Strathcona	3712	150	520	1450
17.	Royal Olympic Hotel	3400	140	480	1340
18.	Harbour Towers	10100	400	1400	3890
19.	Laurel Point	0			0
20.	Courtyard Inn	2800	120	390	1080

POTENTIAL MARKET ANALYSIS - CITY OF VICTORIA

	BUILDING	ANNUAL $BTU \times 10^6$	JULY $BTU \times 10^6$	JANUARY $BTU \times 10^6$	PEAK HOUR $BTU \times 10^3/HR$
Office Buildings					
21.	Bank of Commerce	7356	150	1180	3280
22.	Royal Bank	2000	40	320	890
23.	Belmont Building	500	0	200	550
24.	Wilson Centre	3250	70	520	1440
25.	International House	4350	90	720	2000
26.	Bentall Building	4520	90	730	2030
27.	Montreal Trust	2500	50	400	1110
28.	Sayward Building	3100	60	480	1330
29.	Toronto Dominion Bank	2020	40	320	890
30.	Royal Trust	4200	90	670	1860
31.	Central Building	4500	90	720	2000
32.	Canada Trust	1100	20	180	500
33.	Yarrow Building	5200	100	830	2300
Hospitals					
34.	Victoria General	49400	3140	5610	15600
35.	Royal Jubilee	105,060	4730	13930	35000
36.	Mount St. Mary	3020	120	430	1190
37.	Gorge Road	18330	750	2560	7110

POTENTIAL MARKET ANALYSIS - CITY OF VICTORIA

	BUILDING	ANNUAL BTU X 10^6	JULY BTU X 10^6	JANUARY BTU X 10^6	PEAK HOUR BTU X 10^3/HR
University of Victoria					
38.	Clearihue Boiler Plant	47600	820	5700	15800
39.	Commons Boiler Plant	11300	0	2800	7780
40.	McKinnon Boiler Plant	17000	640	2030	5640
41.	Remainder Boiler Plants	18000	360	2880	8000
Federal Government					
42.	Customs	2320	50	370	1030
43.	Post Office	2900	60	480	1330
Department Stores					
44.	Eatons	10820	430	1510	4190
45.	Bay	9758	390	1370	3800
Miscellaneous					
46.	YM/YWCA	9512	475	1046	2900
47.	Crystal Garden	9940	400	1400	3900
48.	Union Club	3250	130	450	1250
49.	Labatt's Brewery	31320	2540	3130	10000
50.	Harbour Square	0			0
Projections					
Hotel on Songhees Property		10000	400	1400	4000

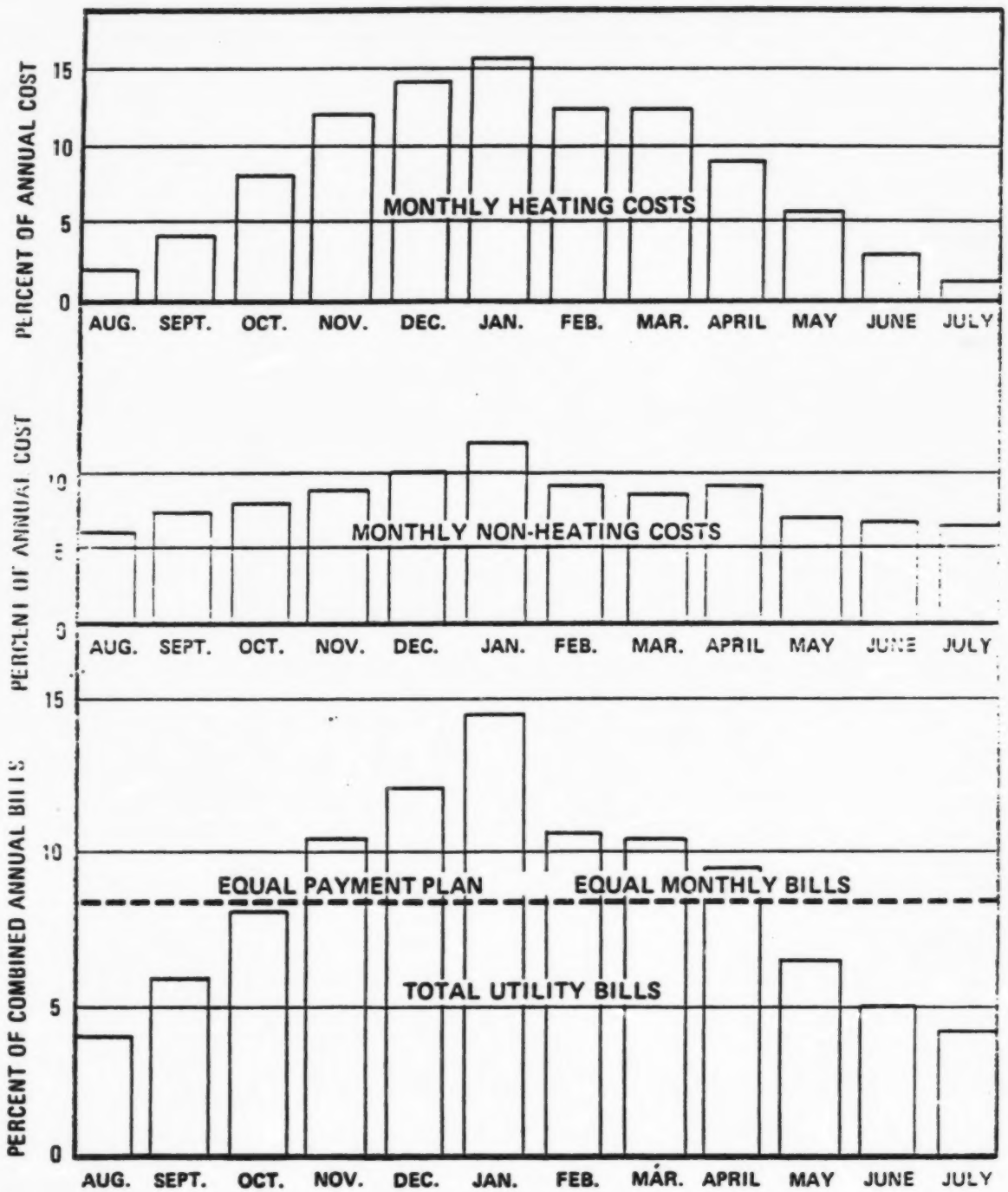
Appendix 1

Distribution of Degree Days Throughout Year - Victoria

	%	F Degree Days	C Degree Days
January	16.0	867	481
February	12.5	676	376
March	12.5	676	376
April	9.0	487	271
May	6.0	325	180
June	3.0	162	90
July	1.0	54	30
August	2.0	108	60
September	4.0	216	120
October	8.0	432	241
November	12.0	649	361
December	14.0	757	421
Total	100.0	5410	3006

E 505
G 505

B.C. HYDRO EQUAL PAYMENT PLAN



The first two charts above illustrate the variations from month to month in heating costs and in the costs of non-heating uses such as lighting and water heating. They are based on an average year.

The third chart combines the first two and also shows the level of the equal monthly payments that would apply under the Equal Payment Plan.

The Equal Payment Plan helps you to avoid large utility bills around the Christmas season by spreading your costs uniformly throughout the year. Ask about it at your local B.C. Hydro office.

Appendix 3

TO: Mr. W. N. Jorgensen

FROM: C. A. Goldie

September 26th, 1968.

RE: PROPOSAL FOR CENTRAL HEATING SYSTEM

The proposal respecting formation of a company to provide a steam heat service in Victoria is at this time very sketchy and indeed is exploratory. No information is given respecting either area or mechanics of distribution other than that the system would employ "low pressure steam" which "is automatically reduced to safe limits by a special valve as it enters the building", and that the area of interest is downtown Victoria with mention of the Wharf Street Renewal area.

Such a general proposal is difficult to evaluate except by voicing a number of equally general queries and comments that appear relevant.

1) Detail is required on pressures and temperatures likely to be employed. How low is "low pressure" that requires reduction to "safe limits"? What are the basic physical requirements such as grade on steam pipes, drainage for condensates, vaults for valves, pipe expansion units or condensate return pumps.

2) What protection is normally afforded against rupture which could occur through (a) weakness or excess pressure
(b) Corrosion
(c) traffic loading
(d) damage caused by subsequent excavation.

Items (a) and (b) should be well taken care of by adherence to standard acceptable practices. Such practice may well also cover items (c) and (d), but it is evident that some form of armour should be required as (i) encasement in concrete - attendant difficulties from expansion and in making connections.
(ii) enclosure in pipe conduit - difficulties in making connections.
(iii) enclosure in conduit with removable lid.

3) Effects of heat loss require consideration. Depending on extent of heat loss and resulting raised ground temperatures, items subject to adverse effects are:-
a) Sidewalk trees
b) Water supply particularly in parallel mains or services
c) Gas services, particularly CI where joint leakage might be promoted.
d) Electrical services employing plastic conduits or insulation.
e) Bituminous road surfaces subject to softening.

4) Conflict with other services severely restricts available space. It is not possible to specify any standard

location for a new service as those existing are not uniformly placed. The downtown area streets commonly contain the following:-

a) Sanitary sewer, generally close to center line and at reasonable depth, usually 8' or more.

b) Storm drain, 8" to 15" one side or other, sometimes both, often shallow 3-6 ft.

c) Water main, 4" to 12" one side or other, sometimes two, approximately 3' cover.

d) Gas main (B. C. Hydro) mostly 4" to 6" one side or other approximately 2' cover normal.

e) Electric ducts (B. C. Hydro) 2' square and larger, 3' or more bury, located both sides of most streets close to curb or in sidewalk.

f) Telephone ducts in street or sidewalk, fairly shallow.

g) Street lighting ducts beneath sidewalk and crossing intersections, shallow.

h) Basement extensions under sidewalks exist on many of the older buildings.

i) Trees are planted on many downtown streets approximately 3' back of curb.

In addition to the above noted mains which run the lengths of streets there are of course many lateral connections from each in addition to various appurtenances as manholes, valve boxes, junction and transformer vaults, etc.

Typical examples with cross sections are attached. Also attached are separate plans showing distribution of water mains, sewers, storm drains, gas mains, telephone and hydro ducts in the area.

Considering the foregoing it is evident that location of any new mains service in the downtown streets will require individual block by block study. From the point of view of city underground services the streets are already too congested but the additional service might be accommodated if it is demonstrably advantageous.

However, such accommodation must be predicated on a policy that City services, both existing and future have precedence, and that private services will be altered at owners expense to avoid conflict.

Construction of steam lines must necessarily be to accepted standards and suitably enclosed. A buried channel with removable lid in which the lagged steam pipe(s) may be suspended might prove most suitable. (This is said, having no knowledge of steam transmission practice). Such an arrangement would provide:-

a) Armour while maintaining accessibility for service connections

b) Freedom for pipe expansion

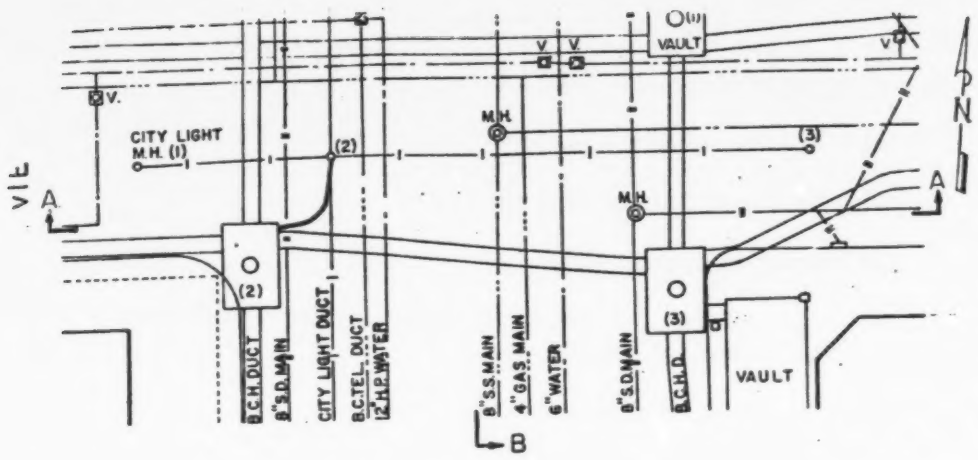
c) Easy recognition

d) Air space around pipe for further insulation and ventilation to junction manholes.

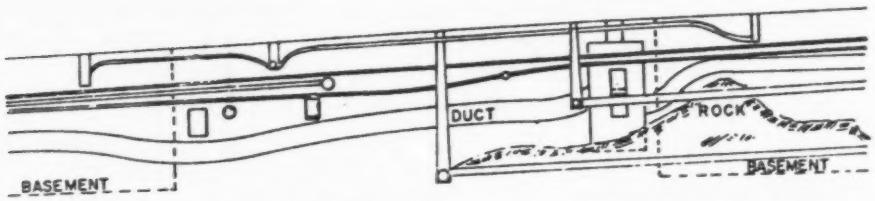
e) Drainage to junction manholes.

f) Controlled escape and easier location of steam leakage.

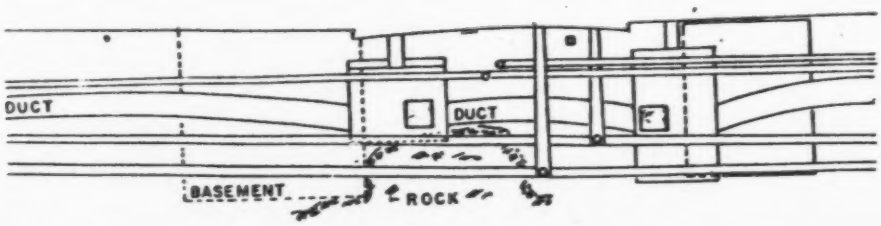
Service connections might be enclosed in suitable pipe from duct to property line. No steam main should be permitted closer than about 5' (outside distance) to parallel mains or services for water, gas, or electricity. Intersecting lines might be permitted to within 18" of each other. With respect to trees it would seem necesary to require a minimum distance of about 15' to avoid soil heating and drying in the Root area.



DOUGLAS ST.



SECTION A-A



SECTION B-B

DWT

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B. H. Levelton & Associates Ltd.
8805 Osler Street
Vancouver, B.C.
V6P 4G1

Reference: Cogeneration Study for
Capital Regional District
Our File No.: 80-5991-V

Dear Sirs:

The purpose of this letter is to enclose copies of the proposed steam heating alternative layouts and to give the information concerning steam heating required in your report. We are not attempting to produce this in the final form. The drawings will need to be reduced in size to conform with your report size and the information will need to be rearranged to suit your index.

You previously sent us your report index from which we could see where the steam heating sections would fit. In Part 1 it appears that the survey information we produced last summer would fit into Section V "Markets for Steam". We should point out that we can only survey the potential market - we cannot respond to "A.1. Establish who could and would purchase steam". All the buildings listed could purchase steam, but whether they would or not is another matter.

With regard to the whole question of what a realistic selling price for the steam will be, the recent announcement that natural gas will be available to customers on Vancouver Island by 1985, changes the rules. It means that (a) RDF generated steam will have to compete with natural gas and not oil. This is very significant at a time when the cost of heating with oil is almost twice that of heating with natural gas - and future predictions are that the gap will widen. (b) We can now use the rate structure of Central Heat Ltd. in Vancouver to establish at what rate customers may be charged for steam. We can use this rate because

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Central Heat has, we believe, kept their rate as high as possible, but has been successful in expanding their service; and Central Heat has had to compete with natural gas.

Central Heat Ltd. have a conventional rate schedule, with the rate decreasing as the consumption increases, plus a fuel cost adjustment in proportion to the increase in their fuel cost. In recent years the fuel cost adjustment has become as high as 50% of their billing. At this point while we are dealing in round numbers there is no reason to analyse their rate structure in detail. The one figure which we think is of most value is that the cost of 3000 pounds of steam per month is very close to $15.00. This rate of steam consumption would be typical for one of the major customers we are considering in Victoria, (e.g. Empress Hotel) and is a useful average figure ($5.00 per M lbs. of steam).

From the information we have, it appears that the Central Heat charges have increased at an annual rate of 15 to 20% for the past five years.

In order to estimate the capital cost of installing the steam and condensate distribution piping we have used historical data obtained from recent installations at the University of Victoria. We have used figures based on the steam and condensate pipes run in a concrete trench with concrete manholes containing isolating valves at each branch. We believe that this is the most reliable system. In any event a conduit type system would be comparable in cost.

Capital cost estimate for installing steam distribution system, February 1981:

Downtown System.	Distribution	$ 2,400,000.00
	Customer Connection	$ 250,000.00
University System	Distribution	$ 1,600,000.00
	Customer Connection	$ 150,000.00

We have included a plan showing the DND Esquimalt System. We are reluctant to attempt to estimate the distribution cost. We have no experience in running underwater lines and to run the piping in salt water across a navicable channel in a military base would seem to be a most unlikely possibility.

The operating cost of a steam distribution will be very small as long as the system is properly installed and there are no material failures. Conventionally the life of such a system is taken to be 50 years. The only items requiring regular maintenance are the steam trap stations. Our best estimate of the annual maintenance cost of the distribution system is:

Downtown System (one man for 8 weeks plus materials)	$ 16,000.00
University System (one man for 6 weeks plus materials)	$ 12,000.00

We have based our sizing of the distribution system on steam being available at 50 psig. The alternative would be 125 psig but we do not think that this would reduce the installation cost significantly.

We anticipate that the next step will be for us to meet and discuss the above with a view to organising the material in a usable form.

Yours very truly,

D.W.THOMSON CONSULTANTS LTD.

Hugh Smith

Hugh Smith, P. Eng.

HS:nt
enclosure